R.02-06-001

Second Report of Working Group 2 on Dynamic Tariff and Program Proposals: Implementation Issues

December 13, 2002

California Public Utilities Commission Order Instituting Rulemaking on Policies and Practices for Advanced Metering, Demand Response, and Dynamic Pricing

TABLE OF CONTENTS

LIST OF TABLES AND FIGURES

LIST OF APPENDICES

EXECUTIVE SUMMARY

In June 2002, the Commission expressed its interest in crafting a comprehensive policy that develops demand flexibility as a resource to enhance electric system reliability, reduce power purchase and individual consumer costs, and protect the environment. "Working Group 2" (WG 2) was established to address the specific issues concerning large customers (those whose average monthly demands exceed 200 kW). WG 2's mission was to develop a tariff or set of tariffs that expand demand response capabilities of large customers. In fulfilling this mission, WG 2 was further directed to pursue its best bet for a "quick win" and to develop full-scale tariffs or programs as opposed to pilots. Supplementing the mission were specific directives to WG 2 such as identifying dynamic pricing triggers, analyzing cost-effectiveness of the proposed tariffs, describing the necessary communication, metering and billing infrastructure, calculating program costs, and evaluating implementation issues.

On November 15, 2002, WG 2 issued its first report, which provided six proposals (four tariffs and two programs) that target large customers. The November 15 Report provides important details regarding the proposals such as how the tariffs/programs operate, the sources for their triggers, their intended levels of participation, and the amount of lead-time necessary to implement them. The November 15 Report also provides pertinent discussion concerning several fundamental considerations that affect tariffs/programs for large customers such as revenue neutrality and voluntary vs. mandatory participation. The November 15 Report also summarizes the state of knowledge based on existing dynamic tariffs within and outside California.

WG 2 now issues this second and final report for consideration. It is intended to supplement the information provided in the November 15 Report. Both reports should be considered together by decision-makers. This second report provides detailed customer education and marketing plans, monitoring and evaluation plans, utility back-office capabilities and a cost-effectiveness analysis for each of the six proposals, as well as a discussion on potential pilot programs for large customers.

Recommendations

The November 15 Report provided six recommendations for consideration. This report documents that consensus recommendations of WG 2 were achieved on the following additional points:

1. Marketing/Customer Education should be coordinated across all utilities and non-utilities, to the extent feasible, to make it as easy for the end use customer as possible.

2. To the extent the Commission desires higher participation in the large customer tariffs than the expectations listed in Section III, the Commission should consider additional customer participation incentives or other means of increasing participation.

3. Because the existing Standard Practice Manual cost-effectiveness tests may not be directly applicable to the evaluation of dynamic pricing tariffs and other market-response programs, the Commission should be cautious in interpreting the results of such tests until after improvements in these tests have been developed and accepted by the Commission and the California Energy Commission.

4. The Commission should adopt the concept of a comprehensive monitoring and evaluation plan as described in Section II.C and authorize cost recovery for such an effort. The utilities and regulatory agencies should be directed to develop a full and complete monitoring and evaluation plan by May 1, 2003. The monitoring elements of the evaluation should be in place in time to help refine the program offerings and information provided to potential customers, and to provide feedback on potential program changes based on initial customer reactions. The impact evaluation should be completed and submitted to the Commission in the Fall 2004, which would result in recommendations for changes in dynamic tariffs or programs being reviewed and decided in late 2004 or early 2005 for actual implementation beginning Spring 2005.

5. The Commission should adopt an ongoing monitoring and evaluation approach regarding all demand response programs. The monthly reports for the interruptible programs now filed pursuant to Ordering Paragraph 8 and Appendix F of Decision No. 02-04-060 should be expanded to include the programs approved in this proceeding. These monthly reports should also highlight any unusual activities or needs for review for these programs.

6. The Commission should approve the recovery of reasonable costs as described in Section VI.B for each of the programs, and joint costs across multiple programs, approved in this proceeding using the standards established in D.01-04-006

7. The Commission should establish a decision-making forum to review and revise demand response tariffs and programs in later 2004 and early 2005 to ensure that monitoring and evaluation results are considered when demand response programs and tariffs are authorized and implemented for summer 2005.

WG 2 represented a diversity of interests in demand response issues for large customers: investor-owned utilities, municipal utilities, large customer associations, ratepayer advocates, various demand response vendors and consultants, energy service providers, utility workers, the California Independent System Operator. Staff from the California Power Authority, the California Energy Commission and the California Public Utilities Commission served as facilitators for WG 2. While the intent of the Working Group process was to develop consensus around a set of proposals, participants in the group carried a diversity of opinion on a number of issues and there were struggles to find common ground in terms of what can be a 'quick win'. See the November 15 Report for more details concerning the nature of the Working Group process and how the process influenced the development of the tariff and program proposals put forward by WG 2.

Customer Marketing and Education

Customer marketing and education are essential elements of demand response programs. Marketing is the activity by which customers are recruited to participate in the programs. All of the programs proposed for large customers (above 200 kW) are proposed to be voluntary, opt-in programs. This means that customers must be informed of the programs, then volunteer to participate .

There are three key elements to a marketing effort. First, program marketers – most likely the utilities – must identify the target market. As noted in the November 15 Report, within the large customer segment, some customers are likely to have greater ability to respond to hourly or critical peak pricing signals, and, thus, should receive greater emphasis in the marketing effort. Some of this receptivity results from previous participation in programs that have been terminated resulting in "orphaned" participants. Second, marketers must identify the appropriate recipients for the information. Because large customers are companies that usually have more than one person involved with energy accounting and energy management, the target recipient is not always obvious. Third, the information content must be appropriate and complete. The information must enable customers to understand the program elements, such as how demand reductions are calculated, how prices are set, and how pricing and usage data are communicated. In addition, the information must be sufficient to allow customers to make a participation decision and actually enroll in the program, if desired. Finally, customers must have the ability to ask questions and otherwise obtain any additional information needed to make a participation decision.

Customer education seeks to facilitate customer understanding of their tariff options and the implications of those options for their energy costs. The goal of educating customers is that they have sufficient information and understanding to make tariff and/or program participation operations choices that are in their own best interest. All recipients of AB29X meters will eventually have the opportunity to access their consumption information.

Although access to energy consumption information is helpful, information on energy usage in and by itself does not provide customers the full picture. Customers must have the ability to view their energy costs along with their energy consumption. In addition to providing both energy usage and cost information, customers must be educated to understand that the cost of using one kWh of electricity at 4 PM on a summer weekday can be very different than using one kWh at 6 AM on a winter weekend day.

Educating customers on how and when they use energy affects their corresponding per unit energy costs is not directly related to any specific demand response program. Rather, it is a necessary step both before marketing any demand response program and after a customer has begun participating in the program.

Monitoring and Evaluation

WG 2 believes that any tariff or program proposal implemented as a result of this proceeding should be monitored and evaluated individually, in terms of its own design intent, and comparatively, across other newly implemented proposals. WG 2 recommends that a comprehensive monitoring and evaluation plan be developed. The results should be used to eliminate those that are failing, refine those that are not performing well, develop new designs, and contribute realistic options into comprehensive procurement decision-making. Monitoring and evaluation activities should achieve two goals. The first is to provide feedback on both implementation activities and customer response and would create a source of ongoing, up-to-date information on the implementation and operation of the program. The second goal would be to document the impacts of the tariff/program on energy use.

Monitoring as WG2 uses the term includes several stages: (1) the recruitment and signup process, (2) tracking continuity of participation over time, (3) measuring actual patterns of demand response using interval data, (4) utility revenue gain or loss, if any, (5) participant expenditures and hardware installations, and (6) utility administrative costs.

Evaluation consists of several analytic activities: (1) identifying the nature of participants compared to the targeted population, (2) assessing actual load shape changes as a function of price or other triggering signals, (3) understanding how participants make load shape changes by manual or automatic mechanisms, (4) estimating utility costs and revenue impacts, and (5) assessing whether program or tariff changes are warranted.

For both monitoring and evaluation, WG2 envisions an intensive effort that goes beyond the routine monitoring and evaluation plans proposed by the utilities in Section III of this report, and thus the need for a comprehensive plan. Once the monitoring and analyses are complete, they should collectively feed into an evaluation of what changes could be made to the tariffs/programs to improve their cost-effectiveness and create sustainable long-term tariffs or programs. It is also necessary to identify the appropriate forum to which such information and preferences could be filed since it is unlikely that R.02-06-001 will still be active at that point in time. In order to comply with tariff and program stability recommendations, WG2 believes it is desirable to allow the program to operate relatively unchanged for two years absent unforeseen difficulties or clear program failures.

Cost Effectiveness Analysis

Based on direction provided by Working Group 1, WG2 applied the Standard Practice Manual (SPM) tests to evaluate the cost-effectiveness of all tariff and program proposals. The tariffs and programs described in this report are in some ways more simple and in other ways different from those usually assessed by an SPM analysis. Therefore, certain adjustments were made to the SPM approach. These adjustments either simplified away unused detail or added capabilities not anticipated in the SPM yet necessitated by the topic of this proceeding. Perhaps the biggest adjustment to note is that the Program Administrator Test was deemed to be unnecessary as the recommendation of WG2 is that utilities receive full cost recovery for these programs via balancing accounts.

In summary, the SPM analysis shows that almost all options are cost-effective when compared against a new peaker, and a number of options, however, are not cost-effective when compared against an existing generator serving load at peak times. The analysis also shows that a great majority of the proposals are cost-effective from a participant's perspective, but that more than a handful of proposals do not appear to have favorable cost-effectiveness results for non-participating ratepayers. It should be noted that WG2 urges that these results be interpreted with caution as WG2 recognizes that improvements and further adjustments to the employed SPM analysis needs to occur.

Furthermore, WG2 notes that there are additional issues related to cost-effectiveness that suggests that further analysis beyond Phase 1 may be necessary. For example, none of the following benefits identified in a previous ALJ ruling have been captured in the SPM analysis: avoided T&D upgrade costs, benefit of any net reduction in air emissions (and other environmental externalities) and value to customers of more timely and accurate information about electricity use. Another issue is how to account for the effect of 'free riders' (e.g., customers who receive a rebate or incentive to participate in a program activity or appliance purchase that they would undertake even without a financial inducement) on the programs' cost-effectiveness. While some WG 2 participants consider free rider participation to generally reduce cost-effectiveness of a program, others argue that if the programs better reflect the cost of providing electricity, 'free ridership' results in a more equitable allocation of costs across different customers than achieved by existing tariffs.

Pilot Programs

Two pilot proposals were raised during WG2 discussions. IMServ-Invensys proposes a tariff that focuses on customers located in constrained transmission and distribution (T&D) areas. The general concept is to give customers reduced T&D charges in return for reducing demand. Potential key benefits of the pilot include avoided T&D upgrade costs, net reduction in air emissions (avoiding use of peakers), participants receiving more timely and accurate information on electricity usage, and lower customer bills. The pilot enables direct access customers to participate. Specifics of this proposal are further described in Section VI.A.

As reported in its November 15 Report, WG 2 was unable to develop a two-part real time pricing (RTP) tariff due to the complexity of developing customer baselines as well as other design issues. In the alternative, WG 2 provided a proposed schedule for the development and implementation of two-part RTP in 2003.

Subsequent to the November 15 Report, Infotility proposed a pilot to evaluate various RTP baseline and customer information issues. See Section VI.B and Appendix C for more details concerning Infotility's proposal. Although not included as a pilot proposal supported fully by WG2 participants, the possible need for a pilot to test RTP tariff design elements is acknowledged by WG2. WG2 agreed that testing alternative design features of a two-part RTP tariff may prove useful. WG2 believes that market research and pilots testing these alternatives may result from the deliberations that it will undertake beginning in January 2003. WG2 notes that should the RTP development team recommend testing two-part RTP tariff design features during 2003 through a pilot, this decision could lead to a delay in the submission of a final tariff proposal and a delay in the date the tariff would become operational. On the other hand, a test of various information display and decision-making aides that do not affect the design of the tariff itself might not delay the implementation date. By raising the possibility of an RTP pilot here, and including a ball park estimate of costs in proposed expenditures, WG2 hopes to create an understanding that would lead to a rapid and favorable response from the Commission should the RTP tariff development team request authority to conduct a pilot.

Next Steps

WG2 believes that following next steps should be addressed in Phase 2 of the proceeding:

1. The Commission should create a mechanism so that the procurement activities underway in R.01-10-024 and the demand response development activities underway in this rulemaking are more completely coordinated. WG2 recommends that R.01-10-024 explicitly delegate to Phase 2 of R.02-06-001 creation of demand response accounting conventions, mechanisms to compare and contrast supply and demand options, and creation of appropriate coordination with the CAISO to support substantial reliance upon demand response as a strategy for UDC bundled service procurement. These Phase 2 methods would be included within R.01-10-024 at a point in late spring or early summer as part of the development of a long term procurement decision that would guide UDC procurement decisions in 2004 and beyond.

2. WG2 recommends that Phase 2 of this rulemaking create a working group process that would be charged with modification of the existing Standard Practice Manual tests and procedures for obtaining input assumptions that would overcome most or all of the SPM deficiencies identified in this report. A proposed SPM revision by this working group would be subjected to a comment opportunity prior to being jointly adopted by the Commission and the California Energy Commission.

3. WG2 was unable to provide proposed tariffs or programs that respond to concerns about transmission and distribution benefits in the design and cost-effectiveness assessment of dynamic tariffs or programs. WG2 believes that greater coordination among agencies is needed before setting out to design dynamic tariffs and programs responsive to these concerns. Once such coordination is in place, then a working group process may be a useful mechanism to design such tariffs and programs and to assess their prospects for acceptance among end-users.

Purpose of This Report

This is the second of two reports provided by WG 2 in accordance with its mission and the directives provided to date. It is important to recognize that this report represents only half of the information needed to make an informed decision about dynamic pricing tariffs for large customers. The report issued on November 15 provided detailed information concerning the six proposals further described in this report.

This second report was not written by a single individual or organization but is the collective product of several participants in WG 2. Participants had an opportunity to submit alternative viewpoints concerning facts, assumptions, analyses or conclusions. These alternative viewpoints have been inserted into the body of report where they are relevant and are clearly identified. It should be noted that some parties have chosen to reserve their substantive comments (which may include alternative viewpoints) until the deadline for comments on both reports, which is December 30, 2002. Thus the absence of alternative viewpoints in this report does not necessarily reflect agreement or consensus amongst the WG 2 participants.

I. INTRODUCTION

On June 6, 2002, the Commission adopted R.02-06-001, its Order Instituting Rulemaking on "policies and practices for advanced metering, demand response, and dynamic pricing." In the Administrative Law Judge's Ruling Following Prehearing Conference, dated August 1, 2002, a procedural framework was established. This framework includes three working groups: WG1 Overall Policy, WG2 Large Customer Issues, and WG3 Small Customer Issues. "Large Customers" is defined as customers with average monthly demands of 200 kW or greater[1].

This is the second of two final reports issued by WG2. The first report, issued on November 15, 2002, provides detailed descriptions of four tariffs and two programs that target large customers. This second report addresses specific implementation issues such as marketing and customer education plans, monitoring and evaluation plans, range of impacts as well as a cost-effectiveness analysis for the tariffs and programs proposed in the first report. This report also includes descriptions of two pilot programs proposed for large customers.

This report includes the following general sections:

- a discussion of key fundamental considerations,
- descriptions of the specific marketing, customer education, monitoring and evaluation plans for the proposed tariffs and programs,
- a cost-effectiveness analysis,
- a discussion of generic implementation issues,
- descriptions of proposed pilot programs for large customers, and
- recommendations for WG1.

The remainder of this Introduction provides a more detailed description of the mission of WG2, the nature of the WG2 process, and the role of this report.

I.A. Mission for >200 kW Customers

[1] The ALJ Ruling definition differs from the definition included in the contracts between the CEC and the utilities. In those contracts, the "End-Use Customer" is defined as "using, on average over the course of a calendar year, more than 200kW of electric energy and power per calendar day. . ." The differences between these definitions point to a need to who precisely should receive RTP metering systems.

The mission for WG2 was defined as: “Expanding demand response capabilities by developing a tariff or set of tariffs to be used for large customers with average monthly demands of 200 kW and above.”[2]
In fulfilling this mission, WG2 was further directed to pursue its best bet for a “quick win” and to develop full-scale tariffs or programs as opposed to pilots. WG 2 was also directed to use the September 9-10 experiential workshops to learn about successful implementation of dynamic tariffs in other parts of the country and to build off that experience in developing dynamic tariffs for California. In addition, WG 2 received several specific directives.[3] These directives and the actions take to address them are listed below:

Table 1: Directives give by WG 1 and Actions taken by WG 2

Directive	Action Taken
“Explore the merits of developing a tariff or set of tariffs that can take immediate advantage of the advanced meters the CEC has installed as a result of ABX1 29.”	WG2 developed a screening process to assess the merits of various tariff options (Nov. 15 Rpt.). In addition, WG2 received and discussed various tariff proposals. Those proposals that remain of interest following the discussions are included in the Nov. 15 Rpt.
“Recommend rate design principles and preferred tariff forms (CPP, TOU, RTP two-part, etc.) for specific rate size classes.”	WG2’s recommended principles are embodied in the screening process described in the Nov. 15 Rpt. WG2 was unable to reach a consensus on a preferred tariff.
“Identify the source and process to compute and communicate wholesale market or other prices that might “drive” a dynamic tariff.”	Each specific tariff proposal identifies the source and process of price signals to tariff participants. (Nov. 15 Rpt.)
“Identify backup sources of prices to define dynamic tariffs if timely wholesale prices are not available or reliable.”	The forthcoming CAISO Day Ahead market has been identified as a potential source for price signals. One potential backup source is day-ahead prices reflected in commercially available index publications such as Dow Jones, Platts and Bloomberg.
“Analyze the cost effectiveness of specific tariffs and identify key uncertainties in the analysis.”	Section IV includes a cost-effectiveness analysis, assumptions and inputs to that analysis, and

[2] August 1 ALJ Ruling, pg. 4

[3] August 1 ALJ Ruling, pg. 5, September 5 ALJ Ruling, pgs. 11-13, October 2 ALJ Ruling, pgs.2-4, 12-16.

	results.
"Recommend specific tariffs for the consideration of Working Group 1 and the full Commission (CPUC)."	WG 2 was unable to reach a consensus in recommending a specific tariff for consideration. The Nov. 15 Rpt. does recommend that the Commission should adopt tariffs/programs reflecting all three types of programs proposed in the report, namely hourly pricing, critical peak pricing and demand bidding.
"Produce a report summarizing recommendations and a plan to implement the specific tariffs, including customer education and demand-side investment requisites."	Specific customer education and marketing plans are addressed in Sections II and III. Generic implementation issues are described in Section V, and as well as in the Nov. 15 Rpt.
"A summary of nontariff program options designed to achieve similar demand reduction objectives."	Nontariff program options are included in the Nov. 15 Rpt. such as a demand bidding program.
"Metering and communication requirements to support the tariffs."	These needs are explained in each of the tariff proposals in the Nov. 15 Rpt.
"Need for additional building controls and or intelligent systems to enhance customer response."	These controls and systems are not required to implement the tariffs, so they were not addressed in the tariff proposals.
"Potential need to upgrade utility billing system capabilities to support the tariffs or programs."	This information is included in the Nov. 15 Rpt. and in Section V.A.
"How these options support customer preferences or customer choice."	This issue is addressed in Section III.D of the Nov. 15 Rpt.
"A recommendation as to whether the tariff should be voluntary or mandatory."	The Nov. 15 Rpt. addressed the voluntary vs. mandatory issue.
"An indication of any necessary coordination with other entities, such as the CAISO."	This was included in each specific tariff proposal of the Nov. 15 Rpt.
"An estimate of administrative costs."	A description of the types of administrative costs along with preliminary cost estimates were included the Nov. 15 Rpt. Final cost estimates are provided in Section V.B.
"A plan for evaluating the results of tariff deployment."	A comprehensive monitoring and evaluation proposal is addressed in Section II and program-specific suggestions

	are made in each subsection of III.
"An analysis of how any existing pilot efforts could be improved to provide more information for further program or tariff development."	The Nov. 15 Rpt. includes a proposal (SDG&E's HPO tariff) for amending an existing pilot tariff. New pilots are proposed in Section VI.
"Recommended next steps for large customers, to be addressed in Phase II of this proceeding."	_WG2's recommended next steps for Phase II are in Section VII.
"We encourage the Working Groups, especially WG 2, to use the two-part tariff concept as they proceed."	The Nov. 15 Rpt. provides a proposed schedule for developing this particular tariff. Additional discussion on this topic is provided in Section VI.B.
Consideration of two distinct approaches: design of a model dynamic pricing tariff available to IOU retail customers and design of a wholesale market bidding program available to all customers including direct access.	Both approaches were covered by the proposals included in the Nov. 15 Rpt. The majority of the proposals address IOU retail customers, while the CPA's Demand Reserves Program is available to all customers, including direct access. IMServ's pilot proposal (Section VI.A) is also open to direct access customers.

I.B. Nature of the Working Group Process

In addition to conducting the specific activities noted above, WG 2 was established as the forum where stakeholders could exchange information and viewpoints, deliberate on the issues, and attempt to develop consensus while pursing their preferred solutions. WG 2 represented a diversity of interests in demand response issues for large customers: investor-owned utilities, municipal utilities, large customer associations, ratepayer advocates, various demand response vendors and consultants, energy service providers, utility workers, and the California Independent System Operator. Staff from the California Power Authority, the California Energy Commission, and the California Public Utilities Commission served as facilitators for WG2.

WG 2 met nearly every week, starting on September 18, 2002 for a total of 11 meetings.[4] All meetings were open to the public and were noticed as workshops in the Commission's Daily Calendar as well as on the Commission's website. Meeting agendas were made publicly available 48 hours prior to each meeting, and minutes for each meeting were drafted and circulated to all participants.

[4] Specific dates of the Working Group 2 meetings were: September 18, 26, October 2, 11, 17, 23, November 1, 12, 19, December 3 and 10.

Copies of the minutes for the first eight meetings were provided in the Nov. 15 Report (Appendix B). Copies of the minutes for the remaining three meetings are provided in Appendix B of this report.

The intent of the Working Group process was to develop the broadest support possible for specific demand response tariffs or programs for large customers. The meetings were facilitated[5] in a workshop format where stakeholders were encouraged to make proposals, provide their opinions, share their experience, and deliberate on issues. Participants also made presentations, provided handouts and materials for review, and answered questions from others. While the intent of the Working Group process was to develop consensus around a set of proposals, participants in the group carried a diversity of opinion on a number of issues and there were struggles to find common ground in terms of what can be a 'quick win'. See the November 15 Report for more details concerning the nature of the Working Group process and how the process influenced the development of the tariff and program proposals put forward by WG 2.

I.C. Role of this Report

The mission of WG 2 is to develop a tariff or set of tariffs for customers with demands greater than 200 kW with the goal of expanding demand response capabilities. The role of this report is to supplement the information provided in the November 15 Report so that Working Group 1 has a complete picture of the tariffs and programs proposed by WG 2 in fulfillment of its mission. The two reports should be considered together by decision-makers as WG 2 believes that the information contained in both reports is relevant.

Like the November 15 Report, this report was not written by a single individual or organization but is the collective product of several participants in WG 2 (see Appendix A for the list of authors). Drafts of each chapter in this report have been circulated among the participants of WG 2 prior to its publication in order to incorporate feedback and differences of opinion. In addition, participants had an opportunity to submit alternate viewpoints concerning facts, assumptions, analyses or conclusions. Alternate viewpoints have been inserted in the chapters where they are relevant and are clearly identified. Parties to the proceeding will also have an opportunity to file their comments on both WG 2 reports by December 30, 2002.

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[5] Mike Jaske of the California Energy Commission served as the Working Group facilitator for each meeting. Bruce Kaneshiro of the CPUC Energy Division prepared meeting notes and David Hungerford of the CEC assembled the report.

II. FUNDAMENTAL CONSIDERATIONS

II.A. Customer Marketing and Education

Customer marketing and education are essential elements of demand response programs. Marketing is the activity by which customers are recruited to participate in the programs. All of the programs proposed for large customers (above 200 kW) are proposed to be voluntary, opt-in programs. This means that customers must be informed of the programs, then either volunteer to participate or not. Only those customers opting into the programs are then enrolled. Education is the provision of information to customers so that they can understand and respond to demand response program features, including pricing.

MARKETING

Marketing of demand response programs provides customers with basic program information, advantages and disadvantages of participation, and an opportunity to participate in the programs. Each of these activities includes specific challenges.

II.A.1.(a) Information

Providing customers with information involves three key elements. First, program marketers – most likely the utilities – must identify the target market. Our understanding is that the programs proposed in the WG2 report of November 15, 2002 will be offered to all customers in the above 200 kW group. However, some customers are likely to have greater ability to respond to hourly or critical peak pricing signals, and, thus, will receive greater emphasis in the marketing effort. Examples of such customers are sand and gravel operators, foundries, and other customers who have participated in demand response programs in the past.

Second, marketers must identify the appropriate recipients for the information. Because large customers are companies that usually have more than one person involved with energy accounting and energy management, the target recipient is not always obvious. The mailing address for the customer is usually the accounting department, while the energy manager is often in another department. For this reason, the utilities have established major account representatives to work with these large customers. These representatives know the customers well and know whom to contact regarding demand response programs and have done so for such programs in the past. However, about half of the customers in the above 200 kW group do not have assigned representatives, so the appropriate contact is not as well known. Thus, a key step in the 2003 program marketing will be to ensure that the proper information recipient is identified for all of the customers in the above 200 kW group. Also, having the email address of the appropriate customer contact would be helpful, since some customers prefer email, and email can be very cost-effective.

Third, the information content must be appropriate and complete. Utilities have had extensive experience with developing such information. The information must enable customers to understand the program elements, such as how demand reductions are calculated, how prices are set, and how pricing and usage data are communicated. In addition, the information must be sufficient to allow customers to make a participation decision and actually enroll in the program, if desired. Finally, customers must have the ability to ask questions and otherwise obtain any additional information needed to make a participation decision.

II.A.1.(b) Advantages and Disadvantages

Customers making participation decisions must understand the advantages and disadvantages of each program. The primary advantage is the opportunity to save money. Major disadvantages include the risk of losing money and the effort needed to reduce peak demands.

One helpful tool is a bill comparison showing what a customer's bill would have been in the prior year on the proposed program versus the default tariff for that customer (a time-of-use rate for the above 200 kW customers). Such comparisons provide an estimate of savings potential, as well as risk of losses. These comparisons are limited in many ways; for example, many external influences change from year to year, such as weather and economic activity. Also, since critical peaks or high hourly price days, by definition, cannot be predicted precisely, bill comparisons can provide only an indication. Customers must understand that these comparisons are only an indicator and not an accurate predictor.

The risk of loss stems from two potential sources, though there are means to address this risk. The first potential source is that the customer's pre-program load profile is worse – more usage on peak – than the class average. This is known as the "structural" loss (or benefit for a low on-peak user). A customer with a worse-than-average pre-program load profile will pay a higher bill by going on the program unless that customer reduces peak or critical peak usage. The second potential source of loss is that a customer is unable to respond as expected. Changes in the customer's circumstances for any variety of reasons may cause the customer's peak usage to rise, thus making the customer pay more on the demand response tariff than on the default.

There are at least three ways to mitigate these risks, all of which have been used for demand response programs in the past. The first is to target customers who are more likely to save on the demand response tariff. This involves more marketing to such customers as well as ensuring that customers who are less likely to shift or reduce on-peak usage are informed that they are unlikely to save by going on the program. The second is to provide a financial incentive to customers to participate. This could be calculated to offset the individual customer's expected structural loss for, say, a summer, so that a customer making no response would pay the same bill at the individual customer level on the demand response tariff as on the default tariff. The incentive approach raises the issue of what to do about customers who have less peak usage than average and thus have a structural benefit of switching. The third risk mitigator is a no-risk trial period. For example, for the first summer of a program, a customer could have the option of participating and paying no more than their default tariff. After that, the customer would have to make a definitive participation decision and accept the risk or not. The third risk mitigator may enable more participation and allow more customers to learn, by doing, whether or not the program works for them.

Once a customer is satisfied that the risk is bearable or offset through appropriate mitigation, the customer must evaluate peak reduction actions. This entails comparing potential actions to expected resulting savings. In this regard, long-term program stability is critical, with five years being desirable. With long-term programs, customers can invest in peak reduction equipment or technologies; otherwise, only short-term, manual actions are typically available. This evaluation includes pre-program calculations and bill comparisons and testing of actual peak reduction activities, if the customer participates in a program.

II.A.1.(c) Participation

The third major element of marketing is signing up interested customers in the program.

In sum, marketing involves informing customers of program features, assisting them in evaluating the advantages and disadvantages of participation, and finally signing up those customers who feel the advantages outweigh the disadvantages.

II.B. Customer Education Proposal

NEED

The ALJ Ruling following the second meeting of Working Group 1, dated October 2, 2002, states:

> "As regulators we keenly appreciate the importance of customer education, and have found it to be critical in launching new regulatory services and programs. We know too, that marketing and customer education, while often lumped together, are not necessarily synonymous. Customer education is our goal, for without it we may fail…"

Recognizing that specific tools are required for customers to participate in demand response, AB 29X provided the funding for the installation of interval metering (IDR), telecommunications and daily access to energy usage for customers with demands over 200kW. With daily access to energy consumption information, customers are gaining a better understanding of their energy usage patterns.

Although access to energy consumption information is helpful, information on energy usage in and by itself does not provide customers the full picture. Customers must have the ability to view their energy costs along with their energy consumption. In addition to providing both energy usage and cost information, customers must be educated on understanding that the cost of using one kWh of electricity at 4 PM on a summer weekday will be very different than using one kWh at 6 AM on a winter weekend day.

Educating customers on how and when they use energy impacts their corresponding per unit energy costs is not directly related to any specific demand response program. Rather, it is a necessary step both before marketing any demand response program and after a customer begins participating in the program. In addition, the benefits of educating all customers on energy usage patterns, regardless of their participation in demand response programs, can result in a "natural" demand response. That is, customers may elect to modify their behavior without directly participating in a demand response program in order to reduce their energy costs (shifting usage from peak to non-peak periods or reducing usage altogether). This is especially true for the above 200 kW customers, since they are all on time-of-use rates already.

PROPOSED ENERGY COST MODULE

Although funding from AB 29X provided for the majority of the metering and information costs for customer participation in demand response, it did not provide funding for viewing estimated energy costs on a daily basis. All three utilities have the capability in its existing system to provide an "Energy Cost" module, which could be made available to customers with IDR metering and communications by summer 2003.

SDG&E estimates its first-year cost to include the "Cost Estimation" module and provide customer education and training is $150,000. Cost estimates for PG&E and SCE to implement customer education and training are not yet available.

Following is a proposed schedule for the implementation of a Customer Education Plan for providing energy cost information:

Table 2: Customer Education Timeline

<table>
<tr><th>Timeline</th><th>Activity</th></tr>
<tr><td>December 2002 –
February 2003</td><td><u>System Enhancements</u>
Evaluate “Cost Estimation” module
Identify modifications and/or enhancements
<u>Market Research</u>
Identify customers
Obtain customer contact information</td></tr>
<tr><td>February –
March 2003

(CPUC approval)</td><td><u>System Enhancements</u>
Test, assess and modify system (if necessary)
<u>Internal Training</u>
Create internal training material
Develop training presentation
Conduct internal training sessions
<u>Customer Collateral</u>
Develop customer communication material
Create customer training material
Develop customer training presentation
Finalize customer collateral
<u>Customer Training</u>
Schedule customer training sessions
Schedule customer meetings</td></tr>
<tr><td>April –</td><td><u>Customer Education</u></td></tr>
</table>

June 2003	• Direct Mail to customers • Attend customer meetings (ongoing) • Conduct customer training sessions (as needed) • Follow-up with customers
September – December 2003	Monitoring and Evaluation • Assess customer usage • Obtain customer feedback • Identify improvements • Recommend enhancements and/or modifications

II.C. Monitoring and Evaluation Plan

The tariffs and program proposals included within the November 15 report represent what participants believe can be implemented by June 2003. Three major ideas guided proposal development during this first phase of Working Group 2 activities. First the need to achieve a "Quick Win" in light of the complexity of the current utility meter data collection, data processing, or billing systems limited, as a practical matter, the options seriously considered by the group to those that will not require substantial changes to that system. Second, concerns about the impact of dynamic tariffs on utility revenue collection in the context of current procurement issues effectively limited consideration of proposals that have the potential for large-scale demand response due to their potential impact on revenue collection. Third, the group's consensus position that these tariffs/programs should be voluntary reflected large customer concerns that these proposals would increase their costs. The resulting proposals thus reflect more short-term pragmatic implementation considerations than the longer-term vision articulated by Working Group 1 at its various meetings. In addition, WG2 participants hold a wide range of expectations about how well these proposals will actually operate. Finally, the Commission procurement rulemaking - R.01-10-024 - and UDC suggestions that supply-side and demand response options receive equivalent treatment require greater information about demand response performance and cost-effectiveness.

Given this uncertainty, any proposal implemented as a result of this proceeding should be monitored and evaluated individually, in terms of its own design intent, and comparatively, across other newly implemented proposals. The individual tariff and program M&E proposals discussed later in this report provide only an individual program perspective. The intended result for the comprehensive monitoring and evaluation plan described here is to refine programs, drop those not working, develop new ones, and contribute realistic options into comprehensive procurement decision-making. Further, WG2 believes this monitoring and evaluation should also encompass existing tariffs and load curtailment programs. Specifically, all of the programs authorized by D.02-04-060 should be monitored and evaluated along with the new programs that may be authorized in Phase 1 decision of this proceeding. WG2 anticipates that at some point the Commission will adjust the balance between various types of programs as greater experience is gained with dynamic tariffs and market-response programs.

The monitoring and evaluation activities should achieve two goals. The first is to provide feedback on both implementation activities and customer response and would create a source of ongoing, up-to-date information on the implementation and operation of the program. The second goal would be to document the impacts of the tariff/program on energy use.

The monitoring and evaluation activities and measurement variables described below will provide information to meet both of the above goals. What is presented in this section of the December 13 report is sufficient for the Commission to understand the goal of the M&E plan and to determine whether it wishes to authorize a comprehensive effort. Once authorized in a Phase 1 decision, the UDCS and regulatory agencies should be directed to develop a full and complete M&E plan by May 1, 2003. The monitoring elements of the evaluation should be in place in time to help refine the program offerings and information provided to potential customers, and to provide feedback on potential program changes based on initial customer reactions. The impact evaluation should be completed and submitted to the Commission in the Fall 2004, which would result in recommendations for changes in dynamic tariffs or programs being reviewed and decided in late 2004 or early 2005 for actual implementation beginning Spring 2005.

MONITORING

Monitoring as WG2 uses the term includes several stages: (1) the recruitment and signup process, (2) tracking continuity of participation over time, (3) measuring actual patterns of demand response using interval data, (4) UDC revenue gain or loss, if any, (5) participant expenditures and hardware installations, and (6) UDC administrative costs. These are somewhat sequential stages of recruiting and operating tariffs and programs, but some stages would overlap.

In each of the following subsections the kinds of data and questions being asked for a specific stage are set out.

II.C.1.(a) Recruitment and Signup

WG2 proposes more intensive tracking of marketing and recruitment than has previously been conducted for load curtailment programs so that these new efforts can be more successful. These data will also allow for greater coordination between new demand response program using dynamic pricing elements compared to conventional load curtailment programs. Which customers respond to marketing and other program opportunity information? Which customers fail to respond? Why? Are there systematic patterns, such as SIC code, building type, business occupancy patterns, etc. Such data items to allow segmentation and market assessment would have to be collected or recorded to the extent they were already features known within UDC customer information or load research systems.

II.C.1.(b) Tracking Continuity

Which customers appear to stick with the tariff or program? Which ones drop off? Why? Qualitative interviews with participants, non-participants, and drop-offs should be conducted to characterize their perspectives for each program. What reasonable suggestions for change do they express? These questions require a longitudinal tracking of participants and "exit interviews" with those who choose to leave the tariff or program.

II.C.1.(c) Measuring Actual Patterns of Demand Response

Chronological interval data for either a sample of participants or all participants (depending upon the level of participation) should be stored outside of the customer information system to allow further analysis. Since most UDC customer data systems allow usage data to "fall out" after 13 months, special archiving may be needed to prevent more costly access later. Contemporaneous price and reliability triggering data should be recorded and stored for future analytic use. For major reliability events, the nature and extent of publicity and other explanatory factors that might be useful in explaining response should also be stored. If feasible, this growing database stored in a format that facilitates later load research and econometric analyses.

II.C.1.(d) UDC Revenue Gain or Loss

Create appropriate mechanisms for determining whether participants are providing greater or lesser revenues that other similarly situated customers not on the tariff or program. This may require creating special revenue tracking mechanisms. It may require creating "shadow" bills that would have generating a customer-specific bill had they continued to be on the standard tariff, and then accumulating the sum of the differences between these bills and actual bills for all tariff participants.

II.C.1.(e) Participant Expenditures

Developing an understanding of participant expenditures is important to ascertaining cost-effectiveness from the participant and societal perspsxctives. To identify specific expenditures or to estimate opportunity costs probably requires conducting a survey of participants to ascertain what techniques they are using to respond to price or reliability signals. What investments in automated load response hardware have been made? What overhead costs can be identified? Responses to such surveys can be used as explanatory variables in load research studies that will attempt to identify what end-use loads have been modified, and at what expense.

II.C.1.(f) Administrative Costs

Create tracking mechanism to identify incremental costs associated with the major elements of the program. The disaggregation of these cost categories must certainly match any CPUC requirements, but may need to be tracked in more narrowly drawn categories if this is important to a process evaluation.

II.C.1.(g) Reporting Monitoring Results

WG2 proposes that the existing reporting requirements for interruptible and load curtailment programs, first required by D.01-04-006 and continued by D.02-04-060, be extended to new dynamic tariffs and programs to encompass some of the routine information gathered about program impacts and administrative costs. Examples of these data include costs, levels of participation, estimated load reductions. For the new program emerging as a result of Phase 1 decision, however, the monitoring information that WG2 suggests be collected is much more extensive, and extends beyond the scope of what has previously been collected for load curtailment program participants. This information does not lend itself to monthly reporting. Instead this information should be collected and updated continuously, and be made accessible to the regulatory agencies and appropriate entities involved in evaluation efforts, using standard methods for any information qualifying for confidentiality protection.

EVALUATION

The evaluation proposal described here extends beyond the proposal-specific evaluation suggestions described later in Section III of this report. Those evaluation activities are suited to short run adjustments whereas this evaluation is designed to support a major “course correction” to validate the “vision” for a high reliance upon demand response as an element of procurement strategies.

Evaluation consists of several analytic activities: (1) identifying the nature of participants compared to the targeted population, (2) assessing actual load shape changes as a function of price or other triggering signals, (3) understanding how participants make load shape changes by manual or automatic mechanisms, (4) estimating UDC costs and revenue impacts, and (5) assessing whether program or tariff changes are warranted.

II.C.2.(a) Identifying Nature of Participants

It is common to segment participants by manufacturing, commercial building, agriculture and water pumping, etc. This is readily accomplished using SIC codes, but becomes more problematic if multi-account, single site customers are aggregated together as a single facility. It is unclear how to classify customers for a meaningful assessment. This may require an iterative process to identify whether business activity is a key determinant of success or failure.

II.C.2.(b) Assessing Load Shape Changes

Assessing load shape change is a key analytic activity. It is probably the most important in determining whether the creation of dynamic tariffs and programs is doing something useful. A key issue is whether this is done in a "before and after" framework or a "compared to non-participants" framework, or both. If it is performed in a comparison to non-participants, then a suitable set of non-participants must be developed as a "control group." This set is not the same as the general class from which the participants came, since some degree of non-representativeness can be expected.[6]

II.C.2.(c) Understand How to Accomplish Load Impacts

Evaluate the survey data about customer response techniques and investments along with actual customer-specific load research data to identify the response techniques with greatest value, from the UDC perspective and the customer perspective. The UDC is probably interested in techniques that create the greatest load shift, while the customer perspective probably focuses on measures or techniques that produce the greatest value per dollar of investment or ongoing operating cost.

II.C.2.(d) Estimating System Benefits

Develop an understanding of how dispatchible programs were actually used. Determine how the load response of participants measures up against specific periods when prices are high and or system supply/demand balances are stressed. What operational integration of demand response programs with UDC procurement decisions has bee accomplished? To what extent have capacity costs been avoided? To what extent has load response avoided expensive generation? Estimate the extent to which market prices were reduced as a result of the program. To accomplish this understanding will require close coordination

[6] The UDC assessments of their dynamic tariffs prepared for WG2 reveals considerable differences in impacts among various customer types, generally focused on what pre-existing load shapes were. To the extent that UDC marketing and customer education materials are successful, then clear "losers" should not be attracted to the voluntary proposals proposed by WG2.

with the CAISO and access to the full body of both UDC procurement and CAISO-organized market data.

This effort should also identify changes in dispatch decision-making that would increase net benefits from using these programs.

II.C.2.(e) Estimating UDC Revenue and Cost Impacts

The assessment effort would use the cost and revenue impact data for each participant to determine aggregate cost and revenue impacts.

II.C.2.(f) Assessing Whether Tariff or Program Changes Are Warranted.

To prepare answers to these many questions requires a sophisticated analytic technique beyond the scope of this report to document. What is proposed here is more intensive than the "routine" M&E plans described for each proposal in Section III of this report. Neenan Associates appears to have prepared such an analysis for the programs operated by the NYISO during summer of 2001.[7] Assuming one of more of the dynamic tariffs and programs suggested by WG2 in its November 15 report are authorized, the Commission should direct UDCs to propose and implement appropriate program evaluation studies. It may be appropriate for UDCs to contract with a recognized vendor with load research and tariff evaluation capabilities to conduct these studies.

Once the previous assessment activities are complete, they collectively feed into an evaluation of what changes could be made to this program to improve its cost-effectiveness and create sustainable long-term tariff or program. It is necessary to identify the appropriate forum to which such information and preferences could be filed since it is unlikely that R.02-06-001 will still be active at that point in time. In order to comply with tariff and program stability recommendations, WG2 believes it is desirable to allow the program to operate relatively unchanged for two years absent unforeseen difficulties or clear program failures. Customers need time to devise improved response patterns and to pay off equipment that has been purchased. When changes are made, they should be incremental. For example, proposed changes to a load bidding program to decrease the payment under high wholesale market process should not occur so rapidly as to "drive off" existing participants.

CONCLUSIONS

WG2 supports development of an intensive monitoring and evaluation plan for demand response programs as described conceptually above. In Section VII.A, WG2 recommends the Commission accept this concept and direct UDCs and regulatory agencies to prepare a detailed plan.

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[7] Neenan Associates, NYISO PRL Program Evaluation: Executive Summary, October 2002.

III. SPECIFIC MARKETING, CUSTOMER EDUCATION, MONITORING AND EVALUATION PLANS

Each of the utilities provided Working Group 2 with analysis of the bill impacts they estimate the proposals could have on selected customers with various load shapes. The degree of net benefits, if any, to customers with various load shapes is clearly an important indicator of the level of participation that might be expected with these voluntary programs. PG&E's analysis was included as Appendix E to the first Working Group 2 Report, 11/15/02. SCE's analysis in included as Appendix E of this report. SDG&E's is included as Appendix F of this report.

III.A. PG&E RTP/CPP Proposal and Joint Utilities Demand Bidding Proposal

GENERAL DESCRIPTION AND OBJECTIVE

PG&E RTP/CPP Proposal and the Joint Utilities Demand Bidding Proposal are programs proposed to Working Group 2. The Programs are designed to test the merits of customers' responsiveness to a price triggered demand response program.

In order to provide a strong interest and attract customers to participate in the Programs, PG&E proposes to utilize an Inform, Persuade, and Remind marketing and customer education strategy. We believe that this strategy would generate awareness, interest, and participation amongst customers by providing the key information and necessary marketing and education collateral to our Account and Business Customer Representatives for strong and effective communication with the targeted customers.

III.A.1.(a) Target Audience

The targeted customers include full services business customers with an average monthly electric demand of at least 200 kW for the last 12 months' period. The targeted customers should already have an interval meter capable of recording metered data on a 15-minute interval. This target audience will include both assigned customers who will be directed toward their respective Account Representative for customer support and unassigned customers who will be directed towards the Business Customer Center (BCC) for further assistance. This potential participant group consists of approximately 7,000 accounts of which about 2,700 have assigned PG&E account representatives.

CUSTOMER MARKETING AND EDUCATION PLAN

III.A.2.(a) Inform

The first stage of the Programs' marketing and customer education plan will serve to inform both the targeted customers, the Account Representatives and all other internal teams that will participate in the marketing strategy of the programs.

The first contact with the customer will be made through a letter mailed to each corporate mailing address. Each letter will contain a list of all accounts under the specific corporate ID. Attached to the letter will be a brochure featuring general information about the Programs as well as a detailed fact sheet discussing the specific requirements for each program. At this stage, all customers will be directed to contact the BCC for assistance or more information.

Before the letter is sent (via direct mail), Account Representatives, Load Management Coordinators and the BCC will be trained on the Programs to enable these teams to prepare accordingly. The advantage of this strategy is to give our customer services team an opportunity to familiarize themselves with the Programs, letter and brochure to be able to better serve the targeted customer group upon contact from individual accounts.

At the same time, PG&E will post the Programs' information on PG&E's public website. This will provide another avenue to our customers to learn more about the Programs and information for participation.

This stage is the most important step in the marketing plan, as this communication effort is the first contact with the customer and their first exposure to the Programs. During this stage, contact will be maintained between the Account Services department in San Francisco, the BCC and the respective Account Representatives and Load Management Coordinators in the field.

The following chart assesses this strategy:

Advantages	Disadvantages
• A letter and brochure allow us to convey a significant amount of targeted and relevant information about the Programs to the target market	• Customers may not read it.

III.A.2.(b) Persuade

The element of persuasion will be introduced in the second stage of the Programs' marketing and customer education campaign. As Account

Representatives serve as our direct link with customers, their communication with individual assigned accounts is critical. PG&E Account Representatives will be contacting their assigned customers individually to follow-up on the letter. For customers that do not have assigned representatives, their interaction with our BCC group forms the essential communication link.

Through both of these channels, customers will receive additional information about the Programs and be able to ask questions to clarify the requirements and specific features of the Programs. Particularly for assigned accounts, this interaction should highlight the key benefits of the programs as they relate to the individual needs of specific accounts. The Account Representatives and the BCC should try to use their expertise in the area of customer relations to persuade targeted customers to sign up for the program.

The following chart examines the advantages and disadvantages to this persuasion strategy:

Advantages	Disadvantages
Account Representatives know their customers' needs and already have a relationship with them. This gives them a stronger position to persuade their customer to sign up for the Programs.	For customers that do not have assigned accounts, such an advantage does not exist. Their only customer service interaction will be through the BCC as opposed to the more personal medium of Account Representatives.
Both the BCC and Account Representatives will be able to gauge customer response to the program through their interaction with customers. This information can be communicated back to Account Services in San Francisco.	Customer interaction through phone calls and meeting is time-consuming and often relies on customers taking the initiative to call first. This may lead to a low response.
If a customer has not read the letter or the brochure, they get another chance to hear about the program upon direct communication with Account Representatives or the BCC.	If a customer has not read the letter or the brochure in the first place, then they will be unlikely to contact their Account Representative or the BCC about it.

III.A.2.(c) Remind

The final stage of the marketing and customer education plan involves follow-up with interested customers based upon feedback and response from both Account Representatives and the BCC.

Depending on their comments and the level of expressed interest in the program, further information may be provided to interested customers through:

- Additional mailings

- A seminar and/or focus group meetings

During this final stage of the marketing and customer education effort, Account Representatives and the BCC should try to sign customers up for the program by having them complete the Customer Agreement Form.

The following chart evaluates the advantages and disadvantages of this strategy:

Advantages	Disadvantages
• Feedback from Account Representatives and the BCC will yield a tailored reminder effort that meets customer needs.	• Customers' level of interest cannot be gauged beforehand, so this section of the marketing plan must remain tentative.
• A seminar or a customer meeting will allow customers to receive information and sign up for the program directly.	• Customers may not want to attend a seminar or a meeting. There may not be substantial interest for it. Also, holding a seminar may add substantially to the budget.
• Additional mailings could give hesitant customers the "last push" to sign up for E-PBIP	• Additional mailings may not be read. They also add substantially to the budget.

PROPOSED SCHEDULE

- Identify targeted customers 2/28/03
- Develop customer letter and Programs brochures 3/5/03
- Train Account & BBC Reps on new Programs 3/7/03
- Post Programs on PG&E public website 3/5/03
- Print Programs brochures.. 3/14/03
- Mail program brochures to targeted customers 3/18/03
- Account Representatives begins contacting assigned customers 3/25/03
- Sign up customers... 3/25/03
- Implement new Programs... 6/1/03
- Marketing and customer education effort evaluation 7/1/03

RANGE OF CUSTOMER PARTICIPATION

PG&E RTP/CPP Proposal would be offered and available to all of PG&E's bundled customers with at least 200 kW of maximum demand that are currently served on PG&E's electric rate Schedules A-10, E19, and E-20. This group consists of approximately 7,000 accounts representing 4,000 MW of aggregate load on typical summer peak days.

Based on work done to date, PG&E believes that 1,000 MW of enrolled load (representing a 25% participation rate) is a conservative upper bound on the number of customers and amount of load that could be successfully recruited to participate in PG&E's RTP/CPP program. If the participating customers contributed an average of 15% load reductions across all of the high-price operating days, this would result in 150 MW of new demand response[8].

PG&E estimates that the participation level for the proposed Joint Utilities Demand Bidding Proposal would include the 40 accounts already participating in the current Demand Bidding Program and there would be an additional 60 accounts for a total of 100 accounts. The existing 40 accounts represent a minimum bidding demand of 6 MW and a maximum bid of 55 MW. When the participation rate increases to a total of 100 accounts, this will represent an additional minimum bidding demand of 9MW (15 MW total) and an additional maximum bid of 82 MW (137 MW total).

MONITORING AND EVALUATION PLANS

This marketing plan is structured around the inform-persuade-remind framework. However, the focus centers on the distribution of information about the Programs.

PG&E currently provides monthly reports to the CPUC on participation levels for existing demand response programs. PG&E plans to continue this reporting for the Joint Utilities Demand Bidding Proposal and to add in its monthly reports the participation levels and load reduction levels for PG&E RTP/CPP Proposal.

III.B. SCE Demand Bidding Program Proposal (DBP)

GENERAL DESCRIPTION

SCE's objective is to re-enroll all those DBP customers who have not renewed their DBP contracts recently, as well as participants in previous versions of the DBP or its predecessors and other interruptible program participants who are able to take advantage of the program with minimal additional effort or cost. As a result of its customer education and marketing efforts described below, SCE

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[8] PG&E is continuing to work with CEC staff and also with staff from the other two utilities to explore policy alternatives that, at additional cost, would be intended to expand the market potential for PG&E's RTP/CPP proposal and provide additional opportunities for commercial office buildings to benefit from this program. PG&E will describe the outcome of these discussions in its December 30 comments, and would also be prepared to provide additional information at the final WG1 policy meeting that is now scheduled for January 7, 2003.

expects to enroll by June 1, 2003 approximately 200 participants in total with an aggregate maximum demand of 300 MWs.

In order to meet this goal by June 1, 2003, SCE has developed an implementation plan, which is itemized below. Since the DBP is an existing program the key implementation steps are related to enhancements to the various systems to accommodate hourly prices for the calculation of the payment and automation of the credit calculation for billing. Presently the bill calculations are performed manually. The steps below assume that this process is automated.

- Educate customers (described below)
- Modify existing bidding system to accommodate a price trigger and hourly prices for the determination of payments to participants
- Develop systems and interfaces to extract hourly prices for billing purposes
- Automate the calculation of the 10 day rolling average baseline and credit
- Develop new customer tracking and reporting documents and training administrative staff in the new tariff operations
- Execute the marketing plan (described below)
- Evaluate and monitor program performance (described below).

Costs to implement the DBP consist of start-up or first-year costs such as billing system enhancements and ongoing costs such as program management and maintenance costs. SCE expects to incur costs related to every activity, but some activities are already funded through current rates. For the purpose of estimating implementation costs, only the incremental costs, i.e., those costs not presently funded in current rates, are shown in the table below. An activity with zero costs is assumed funded by current rates. The estimate for accessing hourly prices for billing for the credit is not included although the estimate for automating the 10-day rolling average is included.

Table 3: DBP Implementation Costs

Activity	First-Year Costs	On-going Costs
Customer Education	1,500	1,500
Customer Marketing	0	0
Modifications to Bidding system for Price Trigger	NA	NA
Modifications to Billing Systems for Hourly Prices	NA	NA
Development of OAT Reporting	46,000	0
Automation of Credit Calc. For Billing	296,000	0

Rate Analysis	20,000	5,000
Evaluation and Monitoring	30,000	0
Program Management	120,000	120,000
Total	513,500	126,500

III.B.1.(a) Customer Education Plan

Customer education for the Demand Bidding Program (DBP) is accomplished through the following: (1) customer classroom training, (2) printed program material, (3) internet website tutorial and sign-on instructions, (4) one-on-one contact by SCE's Major Customer Account Managers and (5) communications letters covering a variety of topics related to program operations, contracts and program information during the year:

Classroom training and printed material are provided to both SCE account managers and customers. This training provides an overview of the program, customer eligibility requirements, an explanation of how the program works, customer benefits, customer sign-up requirements, explanation of what the account manager must do to enroll the customer into the program, what the customer must do to enroll in the program, an overview of bill presentation, and contact information for both customers and account managers. This training is coordinated with other pre-summer customer informational presentations, e.g., energy efficiency, in an effort to maximize the value of the training while minimizing the impact on customers' time away from their work sites.

Training is first conducted with the Account Managers to ensure their understanding of the program before marketing the program to their customers. Customer training then follows account manager training. Based on our experience, account manager and customer training will require multiple sessions in order to accommodate scheduling and geography. In 2001, SCE conducted four sessions for account managers and six sessions for customers. SCE expects to provide about the same number in 2003 for DBP. However, we do expect in conduct the DBP and RTP-MI training, and any other large power customer programs ordered in this OIR, concurrently. Assessment of internal and customer training would be conducted following each training session to determine overall effectiveness of training program.

Printed program materials include standardized presentations for account managers and customers and program fact sheets and Q&A's. This material is made available to the customer through the account managers but is also available on SCE's website. In addition, customers may find information on an SCE website DBP Tutorial as well as website sign-on instructions.

Customer training will continue during the year through the development and delivery of various program communications letters and on-going one-on-one contacts by the account managers.

The development of the training sessions materials, printed material and web site modifications will be initiated upon the effective date of the order in this proceeding. However, in order to address current participant's concerns, prior to designing the material, SCE will initiate the first phase of the market research no later than early January 2003.

III.B.1.(b) Marketing Plan

Marketing the DBP to customers is accomplished in four steps: (1) assessment of current DBP customers attitudes in order to identify those aspects of the program that are most valuable and that can be incorporated into the marketing of the program to new participants, (2) identification of potential new participants, (3) one-on-one contact with these customers by the account managers and (3) on-going presentations to customer groups conducted throughout the year.

SCE intends to conduct a two-phase market research effort concerning DBP. The first phase is a pre-program design completion. As a result of this assessment, we will be able to determine current and former participants' reactions to SCE's existing DBP and the proposed modifications (a price trigger and payments based on a day-ahead market price forecast). For example, we will identify participants' likes and dislikes, barriers and hurdles and operational issues or concerns. Also as a result of this phase of market research, we will be able to assess customers' perceptions of and interest in the new DBP and identify effective ways to communicate DBP to potential new participants. A data analysis of the result will be available after this phase including findings, conclusions and recommendations.

The second phase of the market research consists of a post-program (post-summer 2003) implementation using quantitative and qualitative methodologies. This phase of the market research is described in the evaluation and monitoring section below.

The target customer groups for DBP consist of past DBP participants (those who have participated in the predecessors to the current DBP as well as those participants who opted not to renew their DBP contracts on 2002), current I-6, BIP and SLRP customers not presently on the rate but who have demonstrated the ability and desire to participate in demand response programs.

In the third phase of the marketing plan, account managers will contact directly each potential DBP participant, utilizing the training sessions as a marketing vehicle as well as the various printed education materials to assist customer in understanding program and solicit their participation in the program. In an effort to prioritize account managers customer contact efforts, managers' performance assessments will include incentives to enroll customers in DBP.

Finally, account managers will also incorporate information on the DBP program in presentations to customer groups that focus on California Electricity Marketplace issues. These presentations occur throughout the year, but are conducted primarily pre-summer and throughout the summer.

III.B.1.(c) Range of Customer Participation

Participation level for the proposed Demand Bidding Program depends on the level of incentives offered to participants and the degree of certainty that participants have that they will in fact receive some compensation for participating in the program. When the Demand Bidding Program payments were under the sponsorship of the Department of Water Resources with a payments ranging up to 75 cents per kWh, the program had as many as 173 service accounts with a maximum demand of 303 MWs. However, the DWR never triggered the program. In July 2002 the CPUC authorized SCE to modify the programs to be triggered for reliability and pay participants 35 cents per kWh. The current DBP has also never been triggered. Participation has diminished since that time, which may be attributed to the lack of activity and frequent program changes. Many participant contracts have recently matured and have not been renewed. Currently participation is down to 27 service accounts with a maximum demand of 30 MWs.

SCE expects that with adequate incentive levels, multiple triggering events, and a relatively low trigger price (that will result in presumably more paying events albeit at a lower price) participation could increase to previous levels of approximately 200 service accounts with a maximum demand of 300 MWs (with a minimum bid level, assuming all participants bid, of about 20 MWs).

III.B.1.(d) Monitoring and Evaluation

III1.B.1.(d)1 <u>Monitoring</u>

SCE proposes to monitor the performance of the DBP including but not limited to the following topic areas:

- Recruiting and signup of customers
- Continuation of participation
- Bidding participation and performance by event and by price levels
- Payments to participants
- Participants' investments and/or expense resulting from changing operations in response to the program
- Program administrative and operations costs.

III2.B.1.(d)1 Evaluation

SCE proposes to prepare and submit to the CPUC an evaluation of the DBP performance in the fall of 2004, and make recommendations for modifications, if any are indicated, for the summer of 2005. The evaluation will cover the following:

- Identification of the participants, e.g. SIC codes
- An analysis of bidding, such as bid quantities as a function of the day-ahead energy price forecast (assuming that the market is up and is reliable to use) and bidding participation and compliance rates
- A survey of participants' changes in operations to effect load responsive changes
- A summarization of payments to participants and their costs
- A estimate of system impacts in terms of system demand and energy reductions (avoided costs impacts to be addressed in ex post cost-effectiveness analysis)
- Assessment of the need to terminate or modify the program.

SCE REAL TIME PRICING-MARKET INDEX PROPOSAL (RTP-MI)

III.B.2.(a) General Description

As a result of its customer education and marketing efforts described below, SCE's objective is to enroll by June 1, 2003 a minimum of 26 new RTP-MI participants with an aggregate maximum demand of 23 MWs, out of the target group of approximately 230 non-RTP customers that have the same SIC codes as the majority of current RTP-2 customers.

In order to meet this goal by June 1, 2003, SCE has developed an implementation plan, which is itemized below. Since the trigger for RTP-MI is not yet determined, the task of automating the retrieval of the trigger data is not included.

A key task that is included is the enhancement of SCE's existing rate analysis tool to accommodate the use of hourly demands. To build this capability will require approximately one year at a cost of about $250,000. In the interim SCE proposes to perform this analysis manually and is able to perform this function for the relatively small number of customers anticipated to enroll in RTP-MI. However, SCE emphasizes that the automation of this capability is desirable not only for RTP-MI but also for CPP and any other demand response program that relies on hourly load data. SCE's billing system is not configured to address one at a time what-if analysis such as this and manually doing so for large numbers of customers is not feasible and over time is more expensive than automation. A rate analysis tool is a valuable enhancement that major customer account managers can use to recruit new demand response participants.

The key implementation steps for RTP-MI are as follows:

- Educate customers (described below)
- Modify the current manual retrieval process to access the Market Index information from the designated website (currently temperature data from the National Weather Service) and process the information to generate the required RTP pricing information,
- Develop new customer tracking and reporting documents and training administrative staff in the new tariff operations
- Design and develop a rate analysis tool
- Execute the Marketing Plan (described below)
- Evaluate and monitor program performance (described below).

Costs to implement the RTP-MI consist of start-up or first-year costs such as billing system enhancements and ongoing costs such as program management and maintenance costs. SCE expects to incur costs related to every activity, but some activities are already funded through current rates. For the purpose of estimating implementation costs, only the incremental costs, i.e., those costs not presently funded in current rates, are shown in the table below. An activity with zero costs is assumed funded by current rates. The estimate for accessing the market trigger automatically is not included although the estimate for automating the rate analysis is included.

Table 4 RTP-MI Implementation Costs

Activity	First-Year Costs	On-going Costs
Customer Education	1,500	1,500
Customer Marketing	0	0
Modifications to Billing System	10,000	0
Development of OAT Reporting	46,000	0
Rate Analysis Tool	250,000	0
Evaluation and Monitoring	45,000	0
Program Management	120,000	120,000
Total	472,500	121,500

III.B.2.(b) Customer Education Plan

Customer education for the Real-Time Pricing-Market Index (RTP-MI) is accomplished through the following: (1) customer classroom training, (2) printed program material, (3) internet website tutorial and sign-on instructions, (4) one-on-one contact by SCE's Major Customer Account Managers and (5) communications letters covering a variety of topics related to program operations, contracts and program information during the year:

Classroom training is provided to both SCE account managers and customers. This training provides an overview of the program, customer eligibility requirements, an explanation of how the program works, customer benefits, customer sign-up requirements, explanation of what the account manager must do to enroll the customer into the program, what the customer must do to enroll in the program, an overview of bill presentation, and contact information for both customers and account managers. This training is coordinated with other pre-summer customer informational presentations, e.g., energy efficiency, in an effort to maximize the value of the training while minimizing the impact on customers' time away from their work sites.

Training is first conducted with the Account Managers to ensure their understanding of the program before marketing the program to their customers. Customer training then follows account manager training. Based on our experience, account manager and customer training will require multiple sessions in order to accommodate scheduling and geography. SCE will conduct DBP and RTP-MI training sessions concurrently with an expectation of four sessions for account managers and six sessions for customers. Assessment of internal and customer training would be conducted following each training session to determine overall effectiveness of training program.

Printed program materials include standardized presentations for account managers and customers and program fact sheets and Q&A's. This material is made available to the customer through the account managers but is also available on SCE's website. In addition, customers may find information on an SCE website under "Load Reduction Incentives.

Customer education will continue during the year with the delivery of various program communications letters and on-going one-on-one contacts by the account managers.

The development of the training sessions materials, printed material and any web site modifications will be initiated upon the effective date of the order in this proceeding. However, in order to address current participant's concerns, prior to designing the material, SCE will initiate the first phase of the market research no later than early January 2003.

III.B.2.(c) Marketing Plan

Marketing the RTP-MI to customers is accomplished in four steps: (1) assessment of current RTP-MI customers attitudes in order to identify those aspects of the program that are most valuable and that can be incorporated into the marketing of the program to new participants, (2) identification of potential new participants, (3) one-on-one contact with these customers by the account managers, involving an analysis of rate options, and (3) on-going presentations to customer groups conducted throughout the year.

SCE intends to conduct a two-phase market research effort concerning RTP-MI. The first phase is a pre-program design completion. As a result of this assessment, we will be able to determine current participants' reactions to SCE's existing RTP-2 schedule and the proposed modifications (a price trigger). For example, we will identify participants' likes and dislikes, barriers and hurdles and operational issues or concerns. Also as a result of this phase of market research, we will be able to assess customers' perceptions of and interest in the new RTP-MI and identify effective ways to communicate RTP-MI to potential new participants. A data analysis of the result will be available after this phase including findings, conclusions and recommendations.

The second phase of the market research consists of a post-program (post-summer 2003) implementation using quantitative and qualitative methodologies. This phase of the market research is described in the evaluation and monitoring section below.

The target customer groups for RTP-MI consist of certain industries identified by SIC that have process operations that can shift hours of operations to take advantage of lower prices during SCE's mid-peak and off-peak periods. These industries include construction sand and gravel, asphalt, metal foundries and metal fabrication, petroleum pipelines, industrial gases, and ready-mix concrete. This target group is discussed more in Section III.C. (4) below.

In the third phase of the marketing plan, account managers will contact directly each potential RTP-MI participant, utilizing the training sessions as a marketing vehicle as well as the various printed education materials and rate analysis tools (as available) to assist customers in understanding the program and solicit their participation in the program. In an effort to prioritize account managers customer contact efforts, managers' performance assessments could include incentives to enroll customers in RTP-MI.

Finally, account managers will also incorporate information on the RTP-MI program in presentations to customer groups that focus on California Electricity Marketplace issues. These presentations occur throughout the year, but are conducted primarily pre-summer and throughout the summer.

III.B.2.(d) Range of Customer Participation

While the type of customers that participate in the current RTP-2 tariff span a wide range of SIC codes, participation is concentrated in certain identifiable industries. In order to estimate participation levels in a market-based RTP, SCE identified all customers with demand greater than 200 kW which match the existing RTP-2 load profiles by SIC code and quantified their annual maximum demands. The results of this analysis are presented in Table 1. For estimated participation levels, SCE assumed an 11% penetration rate for potential participants, based on current participation rates for RTP-2. This results in an additional 26 participants and with an aggregate maximum demand of 23 MWs.

Table 5: Target Participants in SCE RTP-MI

Industry (by SIC Code)	Current Participation		Potential New Participants*		Total RTP-MI Participation	
	No.	Max Demand (kW)	No.	Max Demand (kW)	No.	Max Demand (kW)
Constr. Sand & Gravel	17	18.8	5	2.6	22	21.4
Asphalt	9	3.7	1	0.6	10	4.3
Foundries/Fabrication	10	22.8	2	2.4	12	25.2
Air Courier Services	4	5.6	1	0.2	5	5.8
Crude Petro Pipelines	4	14.8	1	1.1	5	15.9
Industrial Gases	4	18.2	1	7.3	5	25.5
Cargo Handling	3	2.2	2	1.3	5	3.5
Ready-Mix Concrete	3	1.4	2	1.0	5	2.4
Refrig. Warehouse	3	5.1	6	4.2	9	9.3
Batteries Manf.	2	1.0	1	0.2	3	1.2
Prod. Of Purch. Glass	2	1.0	1	1.0	3	2.0
Brick & Stone	1	2.6	1	0.1	2	2.7
Industrial Chemicals	1	0.4	1	0.4	2	0.8
Linen Supply	1	0.6	1	0.2	2	0.8
Misc.	32	37.3	0	0.0	32	37.3
Total	96	135.5	26	22.6	122	158.1

* Assumes 11% penetration level for potential participants, based on SCE experience with temperature based Schedule RTP-2.

To demonstrate the impact of the current RTP-2 temperature-based schedule on certain customer types, SCE performed a rate comparison between the generally applicable rate, TOU-8, and RTP-2. Actual customer load profiles from an office building (generally not on RTP), a cement plant (a typical RTP participant), a hospital (generally not on RTP-2) and an average load profile for TOU-8 were used in the analysis. Both actual temperature data from 2001 (a relatively cool year) and adjusted temperature data for the year, that reflects a normal distribution of temperatures, were used as a basis of the comparison.

Under either temperature scenario, each customer type benefits from RTP compared to TOU-8, but clearly the cement plant is an ideal target participant. The savings for an office building are a very modest 1% annually, while the average TOU-8 and the hospital have somewhat better cost savings, 6% and 9 %, respectively. On the other hand, the cement plant saves 17% annually in electricity costs under a normal temperature distribution and up to 29% in a cool year such as 2001. See Appendix E of this report for these detailed assessments.

III.B.2.(e) Monitoring and Evaluation

III1.B.2.(e)1 Monitoring

SCE proposes to monitor the performance of the RTP-MI including but not limited to the following topic areas:

- Recruiting and signup of customers
- Continuation of participation
- Participant load profiles
- Customer's bills compared to their otherwise applicable tariffs
- Participants investments and/or expense resulting from changing operations in response to the program
- Program administrative and operations costs.

III2.B.2.(e)1 Evaluation

SCE proposes to prepare and submit to the CPUC an evaluation of the RTP-MI performance in the fall of 2004, and make recommendations for modifications, if any are indicated, for the summer of 2005. The evaluation will cover the following:

- Identification of the participants, e.g. SIC codes
- Assessing load shape changes as a function of price
- A survey of participants' changes in operations to effect load responsive changes
- A summarization of changes in SCE revenues and participants' costs
- A estimate of system impacts in terms of system demand and energy reductions (avoided costs impacts to be addressed in ex post cost-effectiveness analysis)
- Assessment of the need to terminate or modify the program.

III.C. SDG&E's Marketing / Customer Education Plan

HOURLY PRICING OPTION

III.C.1.(a) General Description

The Hourly Pricing Option (HPO) is a pilot program that provides business customers with hourly energy prices on a day-ahead basis. Customers have the opportunity to decrease energy costs by shifting or reducing electric usage from higher priced to lower priced periods. HPO is currently available on a first-come-first-serve basis to thirty-five (35) non-residential customers with demands greater than 20kW. Some eligibility requirements apply.

SDG&E proposes to modify its existing HPO pilot program for consideration as a full program option for commercial/industrial customers 200 kW or greater who have interval data recorder (IDR) measurement facilities installed. SDG&E also proposes to expand the time periods subject to variable hourly pricing to include the semi-peak hours, which will allow customers greater flexibility in reducing their energy costs. SDG&E believes these modifications are necessary to obtain the level of demand response being sought in this proceeding.

The objective of HPO is to provide customers with price signals in an effort to shift or reduce usage from peak periods to non-peak periods. Customer benefits include reduced energy costs. System benefits include improved system efficiencies.

III.C.1.(b) Customer Education Plan

SDG&E's Customer Education Plan includes developing two analyses tools to evaluate the potential customer impacts by participating in the HPO, creating a customer-specific HPO information package and updating both its Intranet and Internet websites.

The first analysis tool will be used internally and will allow SDG&E to conduct a preliminary evaluation of market segments to identify potential benefits by participating in HPO. After evaluating market segments, the analysis tool can be utilized to evaluate the impact of the rate on specific customer accounts.

HPO participants will utilize the second analysis tool, the Hourly Pricing module. The Hourly Pricing module will provide the next day's hourly prices and allow participants to evaluate these prices with a "similar day" usage pattern in an effort to forecast their next-day energy costs. Participants will also have the ability to conduct "what-if" scenarios that allow them to evaluate the impacts operational changes will have on their energy costs.

In addition to developing HPO analyses tools, SDG&E will develop customer-specific information packages for customers interested in the HPO and for those customers who have accounts that indicate benefits by participating in the HPO. Each package will include an updated HPO presentation and Fact Sheet, a customized rate analysis, a sample customer letter of intent to participate in HPO and schedule for HPO customer training sessions. The HPO presentation will describe the HPO tariff, detail the potential benefits, illustrate the Hourly Pricing module, explain the process of signing up, and how to contact SDG&E for more information.

SDG&E will update its Intranet website to include all the training materials and HPO collateral needed for customer contact personnel to promote the tariff. SDG&E will also update its Internet website to include appropriate information for customers to learn about and evaluate the HPO tariff.

III.C.1.(c) Customer Marketing Plan

SDG&E will conduct a market analysis by identifying the market potential, target market and participant characteristics. Once the market analysis is completed, SDG&E will perform rate analyses to evaluate account-specific impacts of the HPO.

SDG&E account managers assigned to the larger businesses will present the HPO information package to appropriate customer personnel. SDG&E will obtain customer contact information for the medium-size customers and direct mail HPO information packages to them. SDG&E plans to follow-up with customers to gather feedback on their assessment of the HPO.

Following is a preliminary timeline for key customer education and marketing activities:

Table 6: SDG&E HPO Timeline

Timeline	Activity
November 2002 – February 2003	<u>System Enhancements</u> • Finalize internal rate analysis tool • Finalize Hourly Pricing module • Test system enhancements <u>Market Analysis</u> • Identify market potential

	• Identify potential target market • Perform account-specific rate analyses
February 2003	<u>CPUC Decision</u> • Compliance Filing ○ Submit HPO Advice Letter
March – April 2003	<u>Internal Training</u> • Create internal training package • Update customer-contact presentation • Develop HPO rate analyses material • Update Intranet website • Conduct internal HPO training sessions <u>Customer Information collateral</u> • Modify Fact Sheet • Update Presentation • Update Internet website • Create customer information package <u>HPO Launch</u> • Finalize HPO Customer Information Packages • Schedule customer meetings to targeted accounts • Direct Mail to target market (unassigned accounts) • Schedule customer workshop(s)

April – June 2003	<u>Marketing and Promotion</u> • Follow-up with targeted customers • Conduct customer workshops • Conduct customer Hourly Pricing module training

III.C.1.(d) Range of Estimates – Customer Participation

Currently, SDG&E has approximately 1,850 bundled accounts with maximum demands greater than 200kW. SDG&E estimates about 15% of the accounts with demands greater than 500kW will participate in HPO and about 10% of the accounts 200-500kW will participate. Preliminary calculations indicate that a total of about 213 accounts may participate in HPO. Appendix F of this report provides an assessment of the impact of participation for several customers with different load shapes.

III.C.1.(e) Monitoring and Evaluation

Resolution E-3782 states that SDG&E will file two reports to the CPUC Energy Division on the HPO. The first report, due February 1, 2003, is to provide an update on the HPO implementation. The second report, due 60 days following the end of the pilot, is to evaluate the participation levels of effectiveness of the HPO. The expected due date for the second report is November 30, 2003.

The WG2 efforts in this proceeding have resulted in SDG&E proposing to modify the HPO pilot, as mentioned earlier. SDG&E considers these modifications to be significant: 1) expand the pilot to a full-production tariff but offer the HPO to only customers with demands greater that 200kw, and 2) fine-tune the actual HPO methodology to allow greater demand response flexibility.

Previous experience has shown that customers dislike being informed of new programs or tariffs only to be notified shortly thereafter that the program has been significantly modified. The Demand Bidding Program (DBP) and Optional Binding Mandatory Program (OBMC) are recent examples of such changes. With this in mind and in anticipation of CPUC approval in February 2003 of the proposed modifications, SDG&E has not been aggressively promoting the HPO tariff to customers. Instead, its focus has been to adjust the hourly-pricing methodology, finalize the rate analyses tools and foster internal support for the hourly pricing concept to ensure HPO's success. As a result, SDG&E believes the initial report due in February 2003 will have very limited information, if any at all, on implementation efforts and customer participation levels in HPO.

WG2 is proposing in this report to develop a thorough monitoring and evaluation plan for existing demand response programs and those approved in this proceeding. To maintain consistency among all demand response initiatives, SDG&E is proposing to coordinate its HPO reporting with this proceeding by requesting to withdraw the need for a HPO report submission in February 2003. Also, if the CPUC approves to expand the HPO to a full-production tariff, an evaluation of the pilot results due in November 2003 will not be applicable.

JOINT UTILITIES' DEMAND BIDDING PROGRAM

III.C.2.(a) General Description

The Demand Bidding Program (DBP) provides business customers with financial incentives for reducing load on a "day-ahead" or "day-of" basis. DBP is a voluntary program that allows customers to submit "bids" for load reduction when the CA-ISO forecasts supply shortages for the next-day or current day.

Currently, the existing DBP is a reliability-based program that is called when supply shortages are anticipated. The joint utilities (SDG&E, PG&E, SCE) propose to modify the existing DBP to include a price trigger in addition to a system emergency trigger.

The objective of the DBP is to provide options for demand-side resources either when supplies are tight or when wholesale prices exceed certain levels. The DBP provides an alternative to higher spot prices during peak periods.

III.C.2.(b) Customer Education Plan

Upon CPUC approval of the DBP modifications, SDG&E will modify existing customer education DBP material to include "price-trigger" information and system enhancements. DBP educational material includes a customer presentation, Fact Sheet, copy of the DBP tariff and contract. The DBP presentation will describe the DBP, detail the potential benefits, illustrate the Demand Bidding module, describe the process of signing up, and how to contact SDG&E for more information.

SDG&E will update its Intranet website to include all the training materials and DBP collateral needed for customer contact personnel to promote the program. SDG&E will also update its Internet website to include appropriate information for customers to learn about and evaluate the DBP.

SDG&E will also modify its DBP participant Welcome Package. The Welcome Package includes a letter, copy of the signed DBP contract, user ID and password to the Demand Bidding module and training package that describes how to use the Demand Bidding module. .

SDG&E will approach its existing DBP participants to inform them of the program changes. In addition, SDG&E will conduct on-site training of the Demand Bidding module to participants requesting such training.

III.C.2.(c) Customer Marketing Plan

SDG&E will update its 2002 market analysis to identify potential market segments that may be interested DBP based on price triggers.

SDG&E will utilize customer contact personnel to present the modified DBP to larger business customers. SDG&E will direct mail DBP information to the medium-size customers. SDG&E plans to follow-up with customers to gather feedback on their assessment of the DBP.

Following is a preliminary timeline for key customer education and marketing activities:

Table 7: Joint Utilities DBP Timeline

Timeline	Activity
November 2002 – January 2003	<u>Market Analysis</u> • Identify market potential • Update potential target market
February 2003	<u>CPUC Decision</u> • Compliance Filing ○ Submit HPO Advice Letter
March – April 2003	<u>Compliance Filing</u> • Submit DBP Advice Letter <u>System Enhancements</u> • Modify DBP system to accept price triggers • Test system enhancements <u>Internal Training</u> • Create internal training package • Update customer contact personnel presentation • Update Intranet website • Conduct internal DBP system training <u>Customer Information package</u>

	• Modify Fact Sheet • Update Presentation • Update Internet website • Revise customer training material <u>DBP Launch</u> • Finalize DBP Customer Information Collateral • Schedule customer meetings to targeted accounts • Direct Mail to target market (unassigned accounts)
April – June 2003	<u>Marketing and Promotion</u> • Follow-up with targeted customers • Attend customer meetings • Conduct customer workshops & DBP training

III.C.2.(d) Range of Estimates – Customer Participation

SDG&E has sixteen (16) accounts, representing approximately 5.8MW in load reduction currently signed up on the DBP. Based on previous market analyses conducted in 2002 and incorporating the recommended modifications to the DBP, SDG&E estimates 7-10 additional accounts may participate in the revised DBP. Total potential load reduction is estimated to be 8-10 MW.

III.C.2.(e) Monitoring and Evaluation

SDG&E currently provides monthly reports to the CPUC on participation levels for existing demand response programs. SDG&E will continue to report on the modified DBP. When the DBP is initiated, SDG&E will evaluate and report on customer participation and load reduction levels.

In addition, SDG&E will continue to participate in WG2 activities to develop an effective Monitoring and Evaluation plan as described in this report.

III.D. ACWA Critical Peak Price Marketing Proposal

GENERAL DESCRIPTION.

The ACWA CPP proposal is quite simple. Approximately one-half of the current tariff demand charges are not based upon the peak demand anytime during the on-peak period (126 hours during the month) as is the current case, but instead is based upon the average demand during 6 utility-called critical peak hours each month. A total credit of $36/kW is available during these critical peak hours.

CUSTOMER EDUCATION AND MARKETING PLAN

ACWA is proposing a different customer education/marketing plan for this proposal. A recent energy survey of ACWA members found that a significant proportion of them were not aware of existing utility programs in this area (e.g., the utility RTP, DBP, and OBMC tariffs), and most that did know about them didn't understand them. Upon follow-up, the reason became clear.

The utilities' contact person is generally the financial or accounting person. They are the one who pays the utility bills. Any bill inserts or other information from the utilities goes to the financial office, which often does not relay the information to the operations staff in the agency. The financial people are not the ones who decide to participate in alternative tariffs or programs.

The operations staff is responsible for running the system, and deciding if the agency can shift the way they operate and still provide water while saving money. They are often untouched by traditional utility marketing efforts, but they are the ones where the decision making authority to participate in any alternative program rests.

ACWA is proposing that some of the money that traditionally has been spent on utility marketing efforts instead be allocated to trade organizations to pay their expenses in marketing this program. There are a number of trade groups (ACWA, CASA, ABAG, DGS, CLECA, CMA, BOMA, CMTA, CSAC, COPEC, etc,) that have direct contact with distinct segments of the California economy. These trade groups are also often responsible for providing energy information to their constituents, so they are in direct contact with energy decision makers within the member organizations. They are a much better vehicle to use for providing information on a simple alternative like the ACWA CPP program.

ACWA proposes that marketing information (such as brochures and other relevant information) be developed by the utilities as they traditionally have done. Once the background information is available, trade groups be reimbursed for their time and costs incurred in marketing this information to their members for this program.

RANGE OF CUSTOMER PARTICIPATION

The ACWA CPP is an option on existing utility tariffs. Any customer that can control their demand during the six critical peak hours during the month (minimum duration of 2 hours and maximum duration of 4 hours) is eligible for this option on the tariffs. We expect a large number of customers that are currently on the interruptible tariffs that are scheduled to be phased out to migrate to this option. There are currently approximately 1,000 MW of customers on interruptible tariffs.

MONITORING AND EVALUATION

Monitoring and evaluation of performance is somewhat inherent within the design of this program. If the customers do not reduce demand during the critical peak hours they will pay their full tariff costs. If they are able to reduce demand during the critical peak periods their monthly bill will be less. Monitoring and evaluation can be as simple as comparing the customer bills created under current, tradition rates with their costs under the CPP option. Since both the traditional demand level (maximum demand during the on-peak period) and the demand during the critical peak hours are recorded in this program, the simple comparison of those two values on a monthly basis will tell evaluators if a customer is indeed reducing demand during the critical peak hours.

III.E. CPA Demand Reserves Partnership

GENERAL DESCRIPTION.

The Demand Reserves Partnership pays large end users (both bundled service and direct access) for being available to reduce load when needed to function as the equivalent of a Call Option on peaking capacity or Ancillary Services in the wholesale market.

Because the core DRP provides customers a modest reservation payment and a modest energy payment, it is an intermediate option between interruptible rates (large reservation payment and no energy payment) and utility Demand Bidding proposals (no reservation payment and large energy payment).

CUSTOMER EDUCATION AND MARKETING PLAN

CPA believes that utilities should receive credit toward any DR goals for any load on the DRP. Therefore, CPA believes that it should provide information to the utilities so that the DRP can be marketed by the utilities as a customer option along with other DR options. In addition, CPA will have Demand Reserve Providers marketing and educating the customers on the DRP. Further, CPA believes that the Providers should receive a fee for any customers whose leads they generate that yield customers signing up for the utility DR programs.

The Demand Reserve Providers continue to promote the DRP, particularly in encouraging customers to participate by next summer. CPA has had the following associations encourage their members to considering participating in the DRP: Association of California Water Agencies, Building Owners and Managers Association, Silicon Valley Manufacturers Group, California Manufacturing and Technology Association, League of California Cities, California State Association of Counties, California Business Properties Association, Orange County Business Council, California Oil Producers Electric Cooperative, and Golden State Cooperative. CPA will continue to work with these associations to not only promote the DRP, but the other Demand Responsive options as appropriate for their members.

RANGE OF CUSTOMER PARTICIPATION

CPA has had three types of customers express interest in this program:

1. Pumping customers, both oil and water.
2. Industrial, who want more flexibility than they can obtain on an interruptible rate,
3. Commercial, both office building and retail space.

CPA is targeting customers who have over 200 kW at one site. Some sites have multiple meters, including meters less than 200 kW.

To date CPA has received 500 MW of bona fide interest to participate in the DRP.

MONITORING AND EVALUATION

As part of its settlement function with DWR, CPA will be monthly preparing reports on the number of MWs nominated, dispatched and delivered on the program.

IV. COST-EFFECTIVENESS ANALYSIS

This rulemaking was initiated in order to address, comprehensively, policies designed to develop demand flexibility as a resource to enhance electric system reliability, reduce power purchase and individual consumer costs, and protect the environment. (OIR 02-06-001, mimeo, p.1) Working Group 2 was asked to develop a Plan for large customers to include "a complete benefit-cost analysis" (ALJ ruling, 9/5/02, p. 2). The ALJ (Ruling on 10/2/02, p. 7) later offered as an option: "The Standard Practice Manual (for DSM programs) methodology will be used as a tool since it allows an assessment of demand reductions from multiple viewpoints: society; customer; utility; ratepayer." The ALJ elaborated, "we do not wish to turn Phase 1 into a detailed data/modeling exercise … we are simply looking for a range of costs and benefits." (ibid.) Later the ALJ provided a set of avoided cost assumptions that the Working Groups could use and added, "Though we expect cost-effectiveness analysis for all pilot programs and tariffs … at this point, the purpose of the cost-effectiveness analysis is simply informational and may also help us distinguish between various proposals." (ALJ Ruling, 11/13/02, p. 2)

Based on this direction, Working Group 2 applied the Standard Practice Manual to evaluate the cost-effectiveness of all programs. As discussed in the Issues sub-section at the end of this cost-effectiveness discussion, there are some concerns with using the Standard Practice Manual that we believe should be addressed beyond Phase 1.

In summary, this analysis shows that almost all options are cost-effective from the total resource cost perspective when compared against a new peaker (as specified in ALJ ruling 11/13/02). A number of options, however, are not cost-effective when compared against an existing peaker (as also specified in ALJ ruling 11/13/02). Some of the programs are not cost effective from a non-participating customer perspective as described in the analysis section which follows. But as some have observed and as discussed in the Issues section, if these DR options better reflect the costs of providing electricity, such a change may not be less equitable.

IV.A. Description of Framework

The October 2001 "California Standard Practice Manual: Economic Analysis of Demand-Side Programs and Projects" (SPM) sets forth four groups of tests for evaluating Demand Side Management Programs. Each test group examines the program from a different perspective. The SPM describes those test groups and their perspectives as:

TOTAL RESOURCE COST TESTS

"This test represents the combination of the effects of a program on both the customers participating and those not participating in a program. In a sense, it is the summation of the benefit and cost terms in the Participant and the Ratepayer Impact Measure tests, where the revenue (bill) change and the incentive terms intuitively cancel." ... "The benefits calculated in the Total Resource Cost Test are the avoided supply costs--the reduction in transmission, distribution, generation, and capacity costs valued at marginal cost--for the periods when there is a load reduction." ... "The costs in this test are the program costs paid by both the utility and the participants plus the increase in supply costs for the periods in which load is increased." (Pages 23-24).

RATEPAYER IMPACT MEASURE TESTS

"The benefits calculated in the RIM test are the savings from avoided supply costs. These avoided costs include the reduction in transmission, distribution, generation, and capacity costs for periods when load has been reduced and the increase in revenues for any periods in which load has been increased." ... "The costs for this test are the program costs incurred by the utility, and/or other entities incurring costs and creating or administering the program, the incentives paid to the participant, decreased revenues for any periods in which load has been decreased and increased supply costs for any periods when load has been increased." (Page 17)

PARTICIPANT TESTS

"The benefits of participation in a demand-side program include the reduction in the customer's utility bill(s), any incentive paid by the utility or other third parties, and any federal, state, or local tax credit received." ... " The costs to a customer of program participation are all out -of-pocket expenses incurred as a result of participating in a program, plus any increases in the customer's utility bill(s)." (Page 11).

PROGRAM ADMINISTRATOR TESTS

“The benefits for the Program Administrator Cost Test are the avoided supply costs of energy and demand, the reduction in transmission, distribution, generation and capacity valued at marginal costs for the periods when there is a load reduction.” … “The costs for the Program Administrator Cost Test are the Program costs Incurred by the administrator, the incentives paid to the customers, and the increased supply costs for the periods in which load is increased.”

ADJUSTMENTS TO THE SPM METHODOLOGY

The SPM proscribes methods for evaluating Demand Side Management programs. The programs under examination in this proceeding are in some ways more simple and in some ways different from those envisioned in the SPM. In building the evaluation tools used in this cost evaluation, certain adjustments were made to the SPM approach. These adjustments either simplified away unused detail or added capabilities not anticipated in the SPM yet required by this proceeding. The following bullets briefly describe these adjustments.

- Recognize Price Changes – SPM methodology recognizes only quantity changes and not price changes in assessing benefits and costs. However, this proceeding examines quantity changes induced by price changes. Model inputs included both price and quantity changes.

- Calculate Total Changes – SPM methodology uses differential analysis. For instance, the benefit to a participant to a demand reduction would be the demand reduction times the demand price. Extrapolating this differential approach to situations with both price and demand changes would ignore cross term components that might be large with successful demand responses. Hence inputs recognizing these cross components were required.

- Discard Unconsidered Benefit and Cost Components - The SPM includes components not considered at this stage of this proceeding. For instance, the SPM considers alternative fuels. The evaluation tools did not include unused SPM components such alternative fuels.

- Adjust to Continuum – The SPM essentially proscribes using absolute values. For instance, avoiding a cost would show up only as a benefit while increasing a cost would show up as a cost. The evaluation tools simplified the treatment of such a cost by treating a reduction as a benefit that changes sign if it becomes an increased cost.

- Limit to NVP and Benefit Cost Ratio Tests - Each test group in the SPM includes 3 to 5 tests with each including a test of Net Present Value of benefits less costs (NPV Tests) and a test of the ratio of discounted benefits to discounted costs (Benefit/Cost Ratio Tests). The evaluation performed by Working Group 2 only includes NPV Tests and Benefit/Cost Ratio Tests.

- Eliminate Program Administrator Test – In the requested ratemaking environment, where utilities would recover costs associated with demand reduction programs through balancing accounts or other mechanisms, there would be no program administrator costs which are not passed on to non-participating customers. Thus, there is no need for as separate Program Administrator Test.

COST EVALUATION EQUATIONS

Appendix D contains the detailed equations that used to evaluate to programs proposed in this proceeding. The details in the equations easily obscure understanding of what they do and how they relate. In order to gain greater insight it is useful to look at the equations after the present value discounting and summations have taken place. The net present value related equations become:

Total Resource Cost Test

$$NPVTRC = UAC - PRC - PCN$$

Ratepayer Impact Measure Test

$$NPVRIM = UAC - BC - PRC - INC$$

Participant Test

$$NPVP = BC + INC - PC$$

Where

- BC = Bill Changes
- INC = Incentives
- PC = Participant Costs
- PCN = Net Participant Costs
- PRC = Program Administrator Costs
- UAC = Utility Avoided Costs

The figure below shows the relationship between these various cost effectiveness measures. In this framework, the Total Resource Cost Test, the Ratepayer Impact Measure Test, and the Participant Test are consistently related to each other. In particular, the Total Resource Cost Test is essentially the sum of the Participant Test and the Ratepayer Impact Measure Test.

Table 8: Net Present Value Relationships – One Framework

All Ratepayers
NPVTRC = UAC – PRC - PCN

Non-Participating Ratepayers NPVRIM = UAC – BC – PRC - INC
Program Participants NPVP = BC + INC - PC

IV.B. Assumptions and Inputs

GENERAL ASSUMPTIONS

- Evaluation Horizon – Each evaluation applied SPM methodology, adjusted as described above, for 11 years, ten years in addition to the starting year of 2003

- Discount Rate - Each evaluation used the same discount rate of 9 percent. Though each utility would apply a different discount rate it was agreed that 9 percent was a reasonable simplification.

- Proposal Overlap - The tariff proposals are not mutually exclusive with respect to demand reduction overlap. Indeed, some of the proposals might compete for the same demand reduction from the same customer. The evaluation included no attempt to assess this overlap.

CASE SPECIFIC INPUTS[9]

The SPM based cost evaluation equations described above contain six benefit or cost terms. Inputs for each term require yearly estimates. Each proposer provided yearly inputs based upon their best estimate for each of these terms. In making those estimates, proponents were requested to satisfy the following:

- Bill Changes (BC) – As explained in the section describing adjustments to SPM methodology, proponents were asked to provide total rather than differential bill changes. If the proposal delivers its benefit without changing the tariff then a differential approach delivers accurate information.

- Utility Avoided Costs (UAC) – As explained in the section describing adjustments to SPM methodology, proponents were asked to provide total rather than differential avoided cost changes. In addition, the November 13, 2002 ALJ Ruling specified two sets of avoided costs. Proponents were asked to provide inputs using each set.

Participant costs were also estimated. These cost estimates did not attempt to quantify the value of electricity to the customer, i.e., the opportunity cost of the customer's demand reduction. However, because these are voluntary programs, participants will make their own determinations of total costs and volunteer or not on their own.

Appendix D contains the detailed inputs provided by each proponent for each case proposed.

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[9] Final review of anticipated program costs for presentation in the Cost Recovery section of this report resulted in changes. Those changes in turn created differences between the Cost Recovery section and the estimates used here in the final Cost Effectiveness analysis model runs. Two material changes merit notice here. First, PG&E has submitted a final cost estimate for its RTP/CPP proposal that reflects increased costs of about $2.2 million a year (or $20 million NPV), in order to support more comprehensive marketing and customer education efforts. Also, CPA's accounting for incentives in the Transmission Pilot proposal submitted by Invensys would lead to a $1.5 million per year cost increase (or about $10 million NPV). The PG&E increase would affect only the outcome of the TRC test which it would no longer pass for the low avoided cost case of PG&E's CPP proposal. However, PG&E's CPP proposal still passes the TRC test under the high avoided cost values. The CPA change would not shift any tests from passing to not passing."

IV.C. Results

DEMAND REDUCTION

(Note: WG2 urges that these results be interpreted with caution as WG2 recognizes that improvements and further adjustments to the current SPM analyses are needed for this application of the methodology)

These demand reduction amounts were estimated using descriptions from demand reduction proposals and inputs. The line titled **DmdReduc_mWhr** was added to the input worksheets prepared by proponents. It provides the numeric detail of the demand reduction estimate. The following table shows the demand reduction over the hours in which the demand was reduced for each proposal.

CPA	Program	Dmd Recution mW	hrs Reduced	Dmd Reduction mWh
ACWA	CPP	150.00	36	5,400
CPA	CallOp	200.00	100	20,000
CPA	NonSpAS	100.00	100	10,000
CPA	SupEn	150.00	10	1,500
IMS	Trans Pilot	50.00	50	2,500
PG&E	RTP/CPP	150.00	84	12,600
PG&E	DBP	14.00	84	1,176
SCE	DBP	30.00	84	2,520
SCE	RTP-MI	4.60	84	386
SDG&E	DBP	0.32	100	32
SDG&E	HPO	5.90	213	1,257

The demand reduction amounts in this table do not sum to a total demand reduction amount because the proposed programs may overlap. For instance, the ACWA CPP, the CPA CallOp and the PG&E RTP/CPP might all be competing for the same demand reduction from the same potential participant.

Also note that for simplicity, these demand reductions were presumed to be the same in each year. In reality, program ramp up would require some time.

AVOIDED COSTS

With one exception, the participants used the following avoided cost rates for calculating avoided costs.

High Avoided Cost Cases			
Technology	Fixed Avoided Costs	Heat Rate	Fuel Cost
New Simple Cycle Gas Turbine	85.00 $/kW-Yr	10,000 BTU/kWh	3.50 $/mmBTU
Low Avoided Cost Cases			
Existing Peaker	10.00 $/kW-Yr	20,000 BTU/kWh	3.50 $/mmBTU

The exception was the IMServ Transmission Pilot. Avoided costs in this pilot presumed fixed avoided of the amounts shown above plus 15.00 $/kW-yr. This additional amount was included as and adjustment for system operation in congested areas.

RESULTS OF TOTAL RESOURCE COST TEST

NPVTRC = UAC – PRC - PCN

NPVBCR = UAC/(PRC + PCN)

NPVTRC/mWh = NPVTRC/(11 X Dmd Reduction mWh)

High Avoided Cost Case

Proposer	Program	NPV($1000)	Benefits/Costs	NPV/MWh
ACWA	CPP	$92,410	26.91	1.56
CPA	CallOp	$73,303	2.26	0.33
CPA	NonSpAS	$45,762	2.32	0.42
CPA	SupEn	$52,585	2.24	3.19
IMS	TransPilot	$19,902	2.12	0.72
PG&E	CPP	$94,279	27.43	0.68
PG&E	DBP	$7,957	9.12	0.62
SCE	DBP	$18,589	19.97	0.67
SCE	RTPIndex	$1,788	2.46	0.42
SDG&E	DBP	$4,981	79.90	14.15
SDG&E	HPO	$2,344	4.84	0.17

Low Avoided Cost Case

Proposer	Program	NPV($1000)	Benefits/Costs	NPV/MWh
ACWA	CPP	$10,363	3.91	0.17
CPA	CallOp	-$32,769	0.43	-0.15
CPA	NonSpAS	-$7,275	0.79	-0.07
CPA	SupEn	-$30,474	0.28	-1.85
IMS	TransPilot	-$7,265	0.59	-0.26
PG&E	CPP	$14,102	4.95	0.10
PG&E	DBP	$634	1.65	0.05
SCE	DBP	$2,554	3.61	0.09
SCE	RTPIndex	$1,788	2.46	0.42
SDG&E	DBP	$530	9.40	1.51
SDG&E	HPO	-$263	0.57	-0.02

These results show that from a total resource perspective, each high avoided cost case yields a net benefit.

RESULTS OF PARTICIPANT TEST

NPVP = BC + INC - PC

NPVPBCR = (BC + INC)/PC

NPVP/mWh = NPVP/(11 X Dmd Reduction mWh)

High Avoided Cost Case

Proposer	Program	NPV($1000)	Benefits/Costs	NPV/MWh
ACWA	CPP	$51,796	4.45	0.87
CPA	CallOp	$43,407	2.75	0.20
CPA	NonSpAS	$29,605	3.21	0.27
CPA	SupEn	$27,882	2.50	1.69
IMS	TransPilot	$8,256	2.33	0.30
PG&E	CPP	$81,430	6.43	0.59
PG&E	DBP	-$90	0.93	-0.01
SCE	DBP	-$196	0.93	-0.01
SCE	RTPIndex	$19,023	42.35	4.48
SDG&E	DBP	$65	4.48	0.18
SDG&E	HPO	$1,150	1.57	0.08

Low Avoided Cost Case

Proposer	Program	NPV($1000)	Benefits/Costs	NPV/MWh
ACWA	CPP	$51,796	4.45	0.87
CPA	CallOp	$43,407	2.75	0.20
CPA	NonSpAS	$29,605	3.21	0.27
CPA	SupEn	$27,882	2.50	1.69
IMS	TransPilot	$8,256	2.33	0.30
PG&E	CPP	$81,430	6.43	0.59
PG&E	DBP	-$90	0.93	-0.01
SCE	DBP	-$196	0.93	-0.01
SCE	RTPIndex	$19,023	42.35	4.48
SDG&E	DBP	$65	4.48	0.18
SDG&E	HPO	$1,150	1.57	0.08

The Participant Test includes no consideration of avoided costs. Hence the High and Low Avoided Cost Cases yield the same result.

Also note that this test may not fully reflect the value of electricity to customers.

From a participant perspective, this shows that most proposals yield positive results.

RESULTS OF RATEPAYER IMPACT MEASURE TEST

NPVRIM = UAC – BC – PRC - INC

BRCRIM = UAC/(BC + PRC + INC)

NPVRIM/mWh = NPVRIM/(11 X Dmd Reduction mWh)

High Avoided Cost Case

Proposer	Program	NPV($1000)	Benefits/Costs	NPV/MWh
ACWA	CPP	$25,614	1.36	0.43
CPA	CallOp	$29,896	1.29	0.14
CPA	NonSpAS	$16,157	1.25	0.15
CPA	SupEn	$24,703	1.35	1.50
IMS	TransPilot	$11,646	1.45	0.42
PG&E	CPP	-$2,150	0.98	-0.02
PG&E	DBP	$6,676	3.95	0.52
SCE	DBP	$15,785	5.17	0.57
SCE	RTPIndex	-$17,695	0.15	-4.16
SDG&E	DBP	$4,898	34.50	13.91
SDG&E	HPO	-$816	0.78	-0.06

Low Avoided Cost Case

Proposer	Program	NPV($1000)	Benefits/Costs	NPV/MWh
ACWA	CPP	-$56,433	0.20	-0.95
CPA	CallOp	-$76,177	0.25	-0.35
CPA	NonSpAS	-$36,879	0.43	-0.34
CPA	SupEn	-$58,356	0.17	-3.54
IMS	TransPilot	-$15,521	0.41	-0.56
PG&E	CPP	-$82,328	0.18	-0.59
PG&E	DBP	-$647	0.71	-0.05
SCE	DBP	-$250	0.93	-0.01
SCE	RTPIndex	-$17,695	0.15	-4.16
SDG&E	DBP	$447	4.06	1.27
SDG&E	HPO	-$3,423	0.09	-0.25

This shows that ratepayers other than participants will yield a positive or negative net benefit depending upon the proposed program.

IV.D. Issues for Cost-Effectiveness Analyses

First, the August 26th meeting of Working Group 1 devoted considerable time to the difference between the "resource planning" approach and the "economist's" or "price-it-right" approach. During the course of that meeting a consensus agreement emerged for a "preference for a blended and iterative approach to setting quantitative goals, combining resource planning and 'price-it-right' elements" (ALJ ruling, 9/5/02, p.6). At least one party has strongly argued (and a number of parties have shown sympathy for) that a more appropriate approach historically for a benefit/cost analysis under the 'price-it-right' perspective is the standard social welfare (i.e., net societal benefit) formulation[10]:

$$\Delta \text{ social welfare} = -\tfrac{1}{2}\,\Delta P_1\,\Delta Q_1 - \tfrac{1}{2}\,\Delta P_2\,\Delta Q_2$$ [11]

Such welfare analysis is usually developed using customer demand elasticity information. Much of the historical data on elasticities is based on situations with modest variations in prices. There is less experience with very big changes in price – for example, 1200% increase from $.25/kWh to $3.00/kWh.

Other parties have said that other items identified in the ALJ rulings have not been adequately captured in this Standard Practice analysis. For example, none of the following benefits identified in ALJ ruling of 10/2/02 (p. 9) have been captured:

- Avoided T&D upgrade costs,
- Benefit of any net reduction in air emissions (and other environmental externalities)
- Value to customers of more timely and accurate information about electricity use).

Moreover, the ALJ ruling of 11/13/02 stated (p. 3) that " a complete cost-benefit analysis … should include environmental value (criteria pollutant emissions and air quality impacts, land/water use impacts, greenhouse emissions, etc.), insurance/reliability value, market effects, fuel price stability and other criteria that are more difficult to quantify".

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[10] See for example: Acton, Jan Paul and Bridger M. Mitchell, Welfare Analysis of Electricity Rate Changes, Rand Note N-2010-HF/FF/NSF, May 1983; and Borenstein, Severin, Michael Jaske, and Arthur Rosenfeld, Dynamic Pricing, Advanced Metering and Demand Response in Electricity Markets, University of California Energy Institute, Center for the Study of Energy Markets, Working Paper CSEM WP 105, October 2002.

[11] This formula measures the increase in social welfare (net societal benefit) associated with a move from a uniform average electricity price to time differentiated marginal cost pricing. The ΔP's are the change in prices in each separate pricing period, and the ΔQ's are the corresponding change in customer usage in response to the price change.

Another issue concerned the characterization of distributional impacts of demand response programs. In DSM programs, “free riders” (e.g., customers who receive a rebate or incentive to participate in a program activity or appliance purchase that they would undertake even without a financial inducement) are generally considered to reduce program cost effectiveness. The issue is more complicated in evaluating demand response programs. For instance, introducing a voluntary time-of-use rate option allows predominantly off-peak users to receive a lower overall bill without any change in behavior. However, this is arguably still an improvement, since it results in a more equitable allocation of costs across different customers.

There is uncertainty regarding the costs that demand reduction programs are able to avoid as a result of market structure and utility procurement changes. Currently, California electricity markets are based predominantly on a single market-clearing price for electricity that reflects both energy and capacity (scarcity) value.[12] As a result, at peak times the price of electricity can rise sharply (within the constraints of whatever market price cap is imposed), reflecting scarcity payments to owners of capacity. It is these high payments that encourage construction of new capacity by market participants, and provide a visible price signal to customers (through the operation of demand response programs).

The development of some form of capacity obligation is under active discussion at both the state and federal level. A capacity obligation would require load service entities to separately procure capacity resources to cover an amount of load in excess of forecasted requirements (e.g., 112% of expected summer peak demand). This would create a separate capacity market, which would most likely not have visible hourly prices. A similar effect could also result from utility procurement activities. Fully procuring future requirements could result in removing capacity-related prices from the spot market. The impact of this kind of change in market structure on the various demand response programs under consideration in this proceeding has not been assessed.

Many of Working Group 2 believe these issues should be addressed in Phase 2 of this Proceeding as focus on Demand Responsiveness beyond programs/pilots for the summer of 2003 is brought to bear.

[12] Ancillary services are priced separately, but constitute a minor component of the overall electricity market.

V. GENERIC IMPLEMENTATION ISSUES

V.A. UDC Back Office Capabilities

PG&E BACK OFFICE CAPABILITIES

The discussion below is a description of PG&E's back office capabilities to support the implementation of new demand response programs and RTP/CPP tariffs beginning in the summer of 2003. These programs are specific to large customers with average monthly demands exceeding 200 kW. The back office capabilities would include communicating all required information to customers including enrolling customers in the programs, tracking participation, and answering pricing and other program questions. It also includes providing pricing to customers, meter installation, meter data collection including communications, data validation, editing, and estimation and bill calculation.

Costs to implement each of the proposals are provided below. PG&E has the ability to perform the Joint Utilities Demand Bidding Proposal and any one of the RTP/CPP Proposal in the summer of 2003. Please note that PG&E's primary recommendation is to implement the Joint Utilities Demand Bidding Program and its own RTP/CPP Proposal. The additional costs estimates for the other proposals are provided for informational purposes only. If additional proposals are also implemented at the same time, the total cost to operate all the required proposals will need to be reevaluated to take in consideration the additional costs for implementing multiple proposals in the summer of 2003.

V.A.1.(a) Customer Notification System

PG&E's customer notification system is its Inter-Act II system. All new demand response programs and RTP/CPP tariffs to be implemented will use this system to communicate interval meter data information and pricing to the customers. Customers who participate in the demand response programs or RTP/CPP tariffs will be required to use the Inter-Act II system for demand bidding notifications and responses, pricing information, load curtailment event notifications, curtailments, and communications.

V.A.1.(b) Metering and Meter Data Collection

Currently almost all of PG&E's large customers have "real time" interval meters capable of communicating interval meter data information on a daily basis to a meter data collection center. The customer's daily meter data information is then made available for viewing the following day on the Inter-Act II system via the Internet. This process can continue to be used to provide customer access to their meter data regardless of which demand response proposal or RTP/CPP proposal is implemented.

For those large customers who will require a “real time” interval meter to participate in one of the demand response or RTP/CPP proposal, a “real time” interval meter will be installed using PG&E’s current meter installation process.

V.A.1.(c) Billing System

For the Joint Utilities Demand Bidding Proposal, PG&E will need to upgrade the compensation module of its Inter-Act II system. The compensation module will have the ability to calculate the participating customer’s customer specific energy baseline prior to a Demand Bidding Program (DBP) event. The module will also compare the customer’s specific energy baseline to the actual amount of kWh used for that hour during the DBP event to determine if the customer complied with the program and if the customer is eligible for an incentive credit. Billing information created by the compensation module will be reviewed by an analyst and then forwarded to the billing group. The billing group will process the information resulting in the incentive payment appearing as a credit on the customer’s monthly energy bill.

For PG&E’s RTP/CPP Proposal, PG&E will need to upgrade, modify, reprogram, and test its billing system in order to bill RTP/CPP rates to the customer’s energy usage. This includes tariff design and programming, data framing, billing system interfaces, bill presentation and revenue reporting.

V.A.1.(d) Customer Contact

PG&E plans to develop brochures on the PG&E RTP/CPP and Joint Utility Demand Bidding Programs for mailing to all PG&E eligible customers. If additional programs are to be implemented, the brochures will include information on all the programs. In addition, there will be targeted customer contact to promote the programs.

PG&E’s largest customers and businesses that have chain stores are usually assigned to PG&E marketing account representatives. PG&E will train the marketing account representatives on the programs and have them market the programs to their eligible assigned customers. Our Business Customer Center Group will also be trained on the programs to assist and respond to business customers’ inquiries, especially those who do not have an assigned PG&E account representative. In addition, PG&E will promote the programs on PG&E’s public website.

V.A.1.(e) Costs to Implement Individual Proposals

V1.A.1.(e)1 PG&E'S RTP/CPP Proposal

One Time Costs

Customer Notification System	$ 70,000
Metering	$ 40,000
Billing System Modifications	$ 706,000
Customer Contact	see ongoing costs
Total One Time Costs	$ 816,000

Ongoing Costs for 2003

Customer Notification System	$ 170,000
Billing System	$ 580,000
Customer Contact	$ 420,000
Program Management and Reporting	$ 300,000
Total Ongoing Costs	$1,470,000

V2.A.1.(e)1 SDG&E Hourly Pricing Option (HPO)

Under PG&E's RTP/CPP Proposal, the RTP/CPP pricing would apply during a four-month period between June 1 and September 30.

Under SDG&E HPO Proposal, the hourly prices would apply through all the months. The one-time costs to implement this proposal would be similar to PG&E's one-time cost to implement its RTP/CPP Proposal. Major work to PG&E's notification and billing system would be required.

One Time Costs: $ 816,000
2003 Costs: $ 1,700,000

V3.A.1.(e)1 SCE Real-Time Pricing – Market Index Proposal

Under PG&E's RTP/CPP Proposal, the RTP/CPP pricing would apply during a four-month period between June 1 and September 30.

Under SCE Real-Time Pricing Proposal, there will be nine unique schedules that would apply through all the months. The one-time costs to implement this proposal would be similar to PG&E's one-time cost to implement its RTP/CPP Proposal. Major work to PG&E's notification and billing system would be required.

One Time Costs: $ 816,000
2003 Costs: $1,600,000

V4.A.1.(e)1 ACWA Customer Critical Peak Pricing Proposal

Under PG&E's RTP/CPP Proposal, the RTP/CPP pricing would apply during a four-month period between June 1 and September 30.

ACWA Customer Critical Peak Pricing Proposal is a year round program and would restructure the calculation of the customer's demand charges. The calculation would be based on 50% of the demand charge on the customer's peak demand and 50% on the customer's average demand during the Critical Peak Demand Periods. This would apply for all the months.

There would also be a kWh energy credit for reducing demand during the Critical Peak Demand Periods that exceed a monthly base number of 6 Critical Peak Hours.

One Time Costs:	$ 816,000
Ongoing Costs:	$1,700,000

V5.A.1.(e)1 CPA Demand Reserve Partnership (DRP)

Under PG&E's RTP/CPP Proposal, the RTP/CPP pricing would apply during a four-month period between June 1 and September 30.

The CPA Demand Reserve Partnership Proposal, which is based on the CPA's demand bidding program, would assign the CPA's DRP contracts to the utilities.

CPA has indicated that they will continue to interact with the Demand Reserve Providers, calculate the participant's 10 day baseline, and customer demand reserve program payments. The following is a rough cost estimate pending further detail information from the CPA.

Estimated Costs: $100,000 - $300,000

V6.A.1.(e)1 Joint Utilities Demand Bidding Proposal

PG&E's One Time Costs

Customer Notification System	$ 100,000
Metering	$ 10,000
Billing System Modifications	$ 4,000
Customer Contact, Education, Marketing	$ 50,000
Total One Time Costs	$ 164,000

PG&E's Ongoing Costs for 2003

Customer Notification System	$	30,000
Customer Contact, Education, Marketing	$	30,000
Total Ongoing Costs	$	60,000

SCE BACK OFFICE CAPABILITIES

The purpose of this section is to describe SCE's back office capabilities for implementing new tariffs and programs for summer, 2003. In addition to program support and administration, the primary back office functions necessary to support implementation include advanced metering systems, price notification systems, billing systems and rate analysis systems. These functions, coupled with the number of total new rates and programs planned, are the primary drivers that affect SCE's ability to successfully implement such programs for Large Customers within this timeframe.

V.A.2.(a) Advanced Metering Systems

Advanced metering systems (real-time interval metering with supporting data communication systems) are necessary to provide customers with access to their usage information. Such information allows customers to more effectively manage their usage in response to electricity prices. Today, virtually all Large Customers (>200 kW) have advanced metering systems, which allow them to view their hourly energy usage via the Internet. This information, which is posted ex-post and is updated on a daily basis, will allow customers to effectively participate in most of the new and enhance programs proposed in this proceeding.

V.A.2.(b) Price Notification Systems

To some extent, all of the new tariffs and programs proposed in this proceeding will require systems and/or supplementary notification protocols (pager, e-mail, phone, etc.) to effectively communicate prices to customers. Some programs have pre-determined rates that are triggered in response to market price levels. Other programs have variable rates that pass thru market prices. Both types of programs will require either a fully functional market or a market index to serve as the basis for either triggering or determining prices. The Cal-ISO has announced plans to institute a day-ahead hourly market, which may be operational in January 2003. Since the scope of this proceeding involves setting rates in California, the ISO market index would seem to be the most logical index to use as the basis for all new tariffs and programs. However, since there is no prior history associated with this index, it is not possible to gauge the impact of such prices on customers. Until such history can be collected, an alternative source, such as a financial market index, can be used in the interim period. Further work among the WG2 members is necessary to determine the need to identify an appropriate market index that should be implemented on a statewide basis.

Those programs that are “market-triggered”, such as SCE’s RTP-MI and the Joint Utility Demand Bidding program, require a notification or broadcast signal to notify a customer of a load curtailment event and/or a mechanism to communicate the appropriate price schedule or price level that is in effect at a given point in time based on market index prices. SCE is in the process of identifying an appropriate market price index (or a combination of market indices) that would be most suitable. Once this source has been identified, SCE plans to make such price information available to customers through the same Internet site that displays their usage information.

Those programs with variable rates that pass thru market prices, such as a Real-time Pricing rate, will require system development to collect and store the hourly market price information and to translate such information into billing component determinants, which the billing system can then match against usage information and bill customers. Since billing determinants vary based on customer characteristics, including voltage level and customer size, such a system would need to calculate an appropriate price for these different characteristics, by hour and then store this information for billing purposes. SCE had a system that passed thru prices from the Power Exchange when it was operational and is now exploring steps necessary to re-implement such a system.

V.A.2.(c) Billing Systems

The two primary factors that affect SCE’s ability to effectively bill customers are the complexity of the tariffs and the participation levels. Those tariffs that utilize hourly pricing information and/or customer baselines significantly increase the time needed to develop programming logic to apply appropriate prices to appropriate usage levels. Such complex tariffs also increase the amount of data that needs to be stored, monitored and processed for billing purposes. Since SCE’s proposed RTP-MI tariff contains a menu of pre-determined hourly prices, it circumvents the need for a system to separately calculate hourly rates. The complexity associated with calculating the customer baseline for the incentive payment for the proposed Joint Utility Demand Bidding program is such that SCE plans to manually determine CBL’s and incentives for this program for summer, 2003[13]. Such a manual process can only effectively be applied at limited participation levels of less than 200 participants. Should participation levels significantly increase over this amount, system development would be necessary to automate this function, which would increase costs and take time to implement. It is SCE understanding that the other non-IOU proposed tariffs (ACWA) and programs (CPA Demand Bidding) require establishment of a customer baseline. Similarly to the Joint Utility Demand Bidding program, should any of these other programs be adopted, SCE anticipates that it would apply a manual process to calculate customer baselines and bill customers, and then work towards automating this process at a later date. As total participation on

[13] At the same time SCE would work towards automating this process, to be ready at a later date.

the aggregate of all of these types of programs implemented exceeds 200, SCE's ability to effectively bill customers would be significantly impaired.

V.A.2.(d) Rate Analysis Tool for Participant Recruiting

Prior to participating in any voluntary program, large power customers will be provided a rate analysis that compares bills under the new program to those under the customer's otherwise applicable tariff. SCE presently operates a sophisticated automated rate analysis tool for its existing rates. However, the existing system does not have the capability to manipulate metered hourly energy for pricing as will be required for RTP-MI as well as any other offering making use of hourly demands such as CPP. To build this capability will require approximately one year at a cost of about $250,000. In the interim SCE proposes to perform this analysis manually.

V.A.2.(e) The Increasing Number of New Rates and Programs

With limited resources, another compounding factor that affects SCE's ability to implement new tariffs and programs for summer, 2003 is the number of total rates that are planned to be implemented at a given point in time. For Large Customers (>200 kW), SCE is advocating two new programs, the RTP-MI tariff and the Joint Utility Demand Bidding program, which are modifications to existing programs. For Small customers (<200 kW), SCE is considering six new rate options: two variations of a day-ahead fixed Critical Peak Pricing rate for residential customers, two variations of a day-of variable Critical Peak Pricing rate for small C&I customers and two variations of a time-of-use rate for residential customers. Additionally, SCE also plans to implement its bottoms up rate redesign in summer, 2003.

The following discussion focuses on the specific proposals by others.

V1.A.2.(e)1 <u>SDG&E HPO Proposal</u>

SCE estimates that it will require approximately six months of effort and $156,000 to modify the billing system for this proposal and an additional $46,000 to provide the calculation of bills on the standard rate for evaluation purposes. In addition, implementation will require system development to collect and store the hourly market price information and to translate such information into billing component determinants, which the billing system can then match against usage information and bill customers. As mentioned previously, SCE is exploring the time and effort that would be involved in developing such a system.

V2.A.2.(e)1 <u>ACWA Customer CPP Proposal</u>

The automation of SCE's billing system to calculate the adjusted billing demand and the calculation of the credits would require six months of effort at a cost of approximately $210,000. Annual maintenance costs is estimated at $7,200. As stated previous, SCE anticipates that it would apply a manual process to calculate the customer baseline and bill customers, and work towards automating this process at a later date. However, since the ACWA CPP baseline as proposed has no similarity to the 10-day rolling average as contemplated in the DBP, there are no “synergies” to be gained in programming for both programs nor for the manual processes. Thus SCE’s ability to offer and bill both programs (in addition to others), especially if there is significant participation in 2003, could be impaired.

V3.A.2.(e)1 PG&E RTP/CPP Proposal

SCE estimates that implementation of this proposal will require approximately six months at a cost of about $220,000 to automate the billing system. As for all proposals, the feasibility of implementing this program for the summer of 2003 depends on the final number of approved programs and their participation levels.

V4.A.2.(e)1 CPA Demand Reserves Partnership

SCE is in the process of estimating the effort required to implement this program for Summer, 2003.

V5.A.2.(e)1 Constrained T&D Peak Capacity Proposal by IMServ-Invensys

SCE estimates that modifications to the billing system for this proposal would require about six months at an approximate cost of $300,000, primarily to automate the calculation of the 10-day rolling average (similar to that required for DBP). In order to implement by Summer, 2003, SCE would apply a manual process to calculate the customer baseline and bill customers, and work towards automating this process at a later date. SCE’s ability to manually calculate and bill multiple programs would be impaired for participation levels in excess of 200.

SDG&E BACK OFFICE CAPABILITIES

In general, for SDG&E, the cost and lead time required to implement revenue collection processes for the demand response programs described in this report increases in excess of the sum of individual program implementation costs as the total number of programs to be implemented increases.

V.A.3.(a) SDG&E HPO

Billing/revenue collection systems designed for HPO pilot can be converted to full production at minimal cost if HPO program requirements are not materially changed when converted to full production program from pilot status.

V.A.3.(b) SCE Real-Time Pricing – Market Index Proposal

The tariff presents a fixed schedule of hourly commodity energy rates for each hour of the day subject to a day-ahead price trigger. The price schedule that determines the hourly rates to be in effect for the following day would be triggered by either the ISO day-ahead energy price or published day-ahead indices. This approach is similar to the triggers used for Schedule EECC-HPO.

Like the HPO, customers electing service under this rate schedule would do so in lieu of default service under Schedule EECC. Customers would continue to take service for transmission and distribution under a separate non-energy rate schedule.

Estimated costs to revise billing systems to add this option would be approximately $ 100,000.

V.A.3.(c) PG&E RTP/CPP Proposal for Large Customers

The proposal is an optional commodity energy rate applicable for the four month (June-September) summer season. Default commodity energy rates would apply during the winter (October-May) season.

The proposal would be based on a three-tiered system of daily price profiles ("low," "medium," and "high") for the commodity energy rates otherwise charged under Schedule EECC. These price profiles would be established in advance, together with a specific allocation of the number of times each price signal would be applicable.

The proposal assigns 14 "high price," 28 "mid-price," and 42 "low-price" weekdays to the summer season. Rates are identical to default tariff during mid-price days. Prices are higher than default on high price days and lower on low-price days.

Participants would be notified of the applicable price profile on a day-ahead basis. The day-ahead selection would be based on forecast weather and load conditions for the following day.

Estimated cost to collect revenue under this option is $100,000.

V.A.3.(d) ACWA Customer Critical Peak Pricing Proposal

The proposal proposes to implement an optional Critical Peak Pricing rate that will credit customers for reducing demand during Critical Peak Demand periods that exceed a monthly base number of Critical Peak Hours ("Critical Peak Base Hours").

The proposal would also restructure the calculation of customer demand charges currently collected under Schedule AL-TOU. The proposed mechanism would base 50% of the demand charge on customer's peak demand and 50% would be based on customer's average demand during Critical Peak Demand Periods.

SDG&E currently has the capability to collect revenue under a single Critical Peak Pricing charge in its billing systems. However, implementation of a cost-effective version of this scheme would require (1) the creation of a new optional non-energy TOU rate schedule to implement a new methodology for calculation of non-energy demand charges; and (2) a new Critical Peak Pricing credit that would be applied to reduced usage during Critical Peak Demand periods in excess of the specified monthly Critical Peak Base Hours.

Estimated costs to collect revenue under this option range from $100,000 – $250,000 and would take 3-6 months to implement.

V.A.3.(e) Joint Utilities Demand Bidding Program

Adds a pricing trigger to Schedule DBP. Costs to collect revenue (issue credits) under this proposal are minimal.

V.A.3.(f) CPA Demand Reserve Partnership

Under this program, CPA contracts with demand reserve providers to work with end users and be contractually responsible for delivering the load reduction when called. CPA is proposing that UDC procurement functions contract with CPA to provide them with these ancillary and energy services rather than assigning administrative responsibility for this program to the UDCs.

CPA also proposes an “augmentation” in which the IOUs will pay for incremental consumption of bundled service end users on firm and interruptible service. CPA has informed SDG&E that the augmentation program would be administered by CPA as well. The augmentation as proposed would implement two hourly rates (firm and interruptible) subject to a historical customer-specific baseline. This is essentially a two-part rate proposal.

SDG&E estimates that it would cost $100,000 - $250,000 to collect revenue under this option and would take 3-6 months to implement if SDG&E was required to administer the augmentation program instead of CPA.

V.B. Proposed Cost Recovery Mechanisms

Section 6 of WG3’s Report, dated December 10, 2002[14], details the UDCs joint cost recovery proposal. WG2 agrees to apply a similar methodology of cost recovery for WG2 demand response programs and pilots as proposed by the UDCs to provide funding for reasonable expenditures on authorized WG3 experimental statewide pilot programs. WG2 recommends adoption of the proposed Advanced Metering and Demand Response Account (AMDRA) as the method of documenting costs associated with WG2 demand response programs

[14] See Section 6 of Working Group 3’s Report, dated December 10, 2002.

and pilots as described in the sections below. WG2 recommends the Commission also provide funding for the reasonable expenditures of Third Party Vendors (VENDORS)[15] authorized to participate in approved WG2 demand response programs and pilots to the extent the Commission adopts such programs and pilots.

WG2 consents to the proposed cost recovery mechanisms detail below, and a total 2003 budget cap of $19 million, which includes funding for both authorized WG2 demand response programs and pilots.[16] Incentive payments and energy bill changes[17] are part of procurement and therefore not subject to the budget cap. This cap does not include funding for programs proposed for WG3. Table 9 below details the 2003 estimated WG2 demand response program and pilot expenditures[18].

The IMServ Critical Peak T&D pilot proposal could apply to customers above and below 200 kW, cost about $3,650,000, of which $2,000,000 is expected to apply to customers below 200 kW, $650,000 would apply to customers above 200 kW, and $1,000,000 is to apply to incremental metering systems costs.[19]

WG2 agrees that future budget cap changes could be proposed through annual advice letter filings at the Commission's Energy Division. WG2 recommends the Commission allocate the AMDRA total 2003 budget cap between the UDCs according to which programs are authorized and which UDC implements that program (because those costs vary by program, WG2suggests that proposed allocations be included in the draft Phase I decision and that the Parties be allowed to comment on the allocations, based on estimated program costs for the programs adopted in the draft decision). WG2 recommends that all activity associated with WG2 demand response programs and pilots be reported to the Commission monthly.

The costs included in Table 9 include monitoring and evaluation plans[20], marketing and customer education plans[21], customer notification systems for

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[15] Infotility, ACWA, and IMServ.

[16] See Table 9.

[17] See Table 10.

[18] Some estimated expenditures could include some 2002 costs.

[19] Of the IMServ Program Administration budget, $150,000 is to cover utility costs, and the rest is to cover CPA costs.

[20] See Section II.C and Section III of this Report for more details.

[21] See Section III of this Report.

pricing and critical peak events[22], metering and meter data collection for customers who do not have meters under the ABx1 29 funded real-time metering program[23], Billing system modifications[24] (Section V), and other operations and maintenance and administration costs as necessary.

As noted above, details of program activities and costs are provided in Sections II.C, III, and V of this report. Additional details are provided in Section V of WG2's November 15, 2002 report. Sections of that report provide details on the implementation of each of the proposals and subsection (5) for each of the proposals specifically describes Sources and Levels of Costs.

WG2 recommends that the Phase I decision in this proceeding, include authorization for VENDORS to recover reasonable costs of participation in authorized WG2 demand response programs and pilots. Funding for VENDORS could be through UDCs AMDRA, the CEC's PIER[25], or the CPUC's Public Goods Charge. The PIER and Public Goods Charge are already in place and are consistent with the basic intent of that charge. Since several options are available, the Parties are encouraged to address this issue more specifically in their December 30 comments to this report.

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[22] See Section IV of this Report.

[23] Most customers above 200 kW have such meters, but some do not.

[24] See Section V of this Report.

[25] For funding purposes, Some portions of WG2 demand response programs and pilots could be considered research programs.

TABLE 9: 2003 Estimated Expenditures on WG2[26] Demand Response Programs and Pilots[27]

Proposer	Program Name	Program Administration Costs (O&M + A&G) for Calendar Year 2003	Capital Costs for Calendar Year 2003	Total
ACWA	CPP	$400,000	$600,000	$1,000,000
CPA	CallOp	$1,200,000	$2,000,000	$3,200,000
CPA	NonSpAS	$1,000,000	$3,500,000	$4,500,000
CPA	SupEn	$1,000,000	$1,500,000	$2,500,000
CPA	ISO Credit	$1,000,000	$1,000,000	$2,000,000
Infotility	TPRTP	$155,000	$145,000	$300,000
IMServ	CPT&D	$650,000	$1,000,000	$1,650,000
PG&E	RTP/CPP	$2,246,000	$40,000	$2,286,000
PG&E	DBP	$214,000	$10,000	$224,000
SCE	RTP-MI	$449,000	$0	$449,000
SCE	DBP	$513,000	$0	$513,000
SDG&E	DBP	$8,000	$7,000	$15,000
SDG&E	HPO	$50,000	$240,000	$290,000
TOTAL (proposed cap)		$8,885,000	$10,042,000	**$18,927,000**

[26] The Program Administration Costs in the table below for the CPA options are half to cover utility incremental costs and half to cover CPA incremental costs. The Capital Costs for the CPA program, except for $2,500,000 in incremental software development for better handling of meter data to support Demand Response consistent with ISO practices, provide $5,500,000 more for CEC meters. CPA recommends the allocation of these costs to be for PG&E, Edison, SDG&E, respectively: Program Administration (45%, 45%, 10%), Capital Costs (53%, 14%, 32%). PG&E is provided a higher capital percent because most of its Pumping customers do not have CEC meters.

[27] The $2.5M cost estimate reflects the need for PG&E to develop and implement CPP billing capability and to undertake an aggressive marketing effort to 8,000 of PG&E's largest customers (>200kW). Some of these costs have been included in PG&E's 2003 GRC, if the Commission approves recovery of these costs in the GRC, PG&E will modify its recovery proposal in this proceeding to ensure costs are not recovered twice. This estimate excludes approximately $1.12 million in funds requested in the GRC associated primarily with public carrier air time charges for retrieving interval data format he Abx1-29 meters.

METHODS OF COST RECOVERY

WG2 recommends the UDCs be allowed to: (1) establish regulatory accounts to record incremental one-time and on-going demand response program and pilot costs not currently covered in rates, (2) utilize established balancing accounts to recover under collected revenues, (3) utilize established balancing accounts to recover customer incentive payments, and (4) provide for VENDORS to recover reasonable expenditures to participate in authorized WG2 demand response programs and pilots.

WG2 recommends the following cost recovery treatment for all UDC and Vendor reasonable costs to assess, acquire, deploy, install, operate and maintaining advanced meter technologies. Also, all reasonable costs related to communication hardware, billing systems, and measurement data collection software enhancements. UDCs and VENDORS should also be allowed to recover all incremental costs to design, implement, and market authorized WG2 demand response programs and pilots.

V.B.1.(a) O&M and A&G Costs to Implement Large Customer Tariffs Incurred Prior to the Phase I Decision

WG2 recommends the Commission provide authorization in its Phase I decision for the UDCs and VENDORS to include and recover reasonable costs associated with various activities necessary to implement authorized WG2 demand response programs and pilots for large customers by June 2003. WG2 recommends the Commission authorize the UDCs to create a regulatory account to record one-time and on-going incremental operations and maintenance (O&M) and administrative and general (A&G) costs associated with work prior to a Phase I decision. Details of the proposed AMDRA are described below. Prior to the Phase I decision, the AMDRA would be capped at $1 million for both Working Group 2 and 3. Each year's recorded WG2 demand response program and pilot costs will be recovered in the subsequent year via an annual advice letter filing at the Commission.[28]

V.B.1.(b) O&M and A&G Costs to Implement Large Customer Tariffs Incurred Subsequent to the Phase I Decision

One-time and on-going incremental O&M and A&G cost estimates will probably change after the Phase I decision, and certainly over the next five years. WG2 proposes that the Phase I decision order a methodology to change the total budget cap in the AMDRA. We recommend using the annual advice filings for the

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[28] Alternatively PG&E or SCE could seek cost recovery in the Revenue Adjustment Proceeding (RAP), although the timing and frequency of future RAPs are uncertain. If the Commission discontinues use of the RAP as a summary rate and revenue adjustment, SCE and PG&E propose to apply interest to these amounts and to recover them in the next rate case.

AMDRA as the place for the UDCs to propose changes in the AMDRA budget caps. For separate tracking purposes, WG2 demand response program and pilot costs prior to the Phase I decision could be recorded in a sub account of the AMDRA.

V.B.1.(c) Capital

WG2 recommends that all reasonable capital additions incurred in WG2 demand response programs and pilots should be treated as authorized additions to the respective UDCs plant and associated annual depreciation expense as authorized by the Commission for each UDC. Authorized capital expenditures could be on a per customer basis for certain specific variable plant additions, e.g., advanced meters, or on a total estimated basis, e.g., billing system addition or measurement data collection software.[29]

V.B.1.(d) Incentive Payments

WG2 recommends that for Commission authorized WG2 demand response programs and pilots requiring an incentive payment, those payments would be recorded in the appropriate regulatory account.[30]

V.B.1.(e) Revenue Shortfalls

There is a consensus in WG2 to allow the recovery of UDC revenue shortfalls due to load shifting, load reduction, or bill credits from WG2 demand response programs and pilots offered to bundled service customers from all bundled customers through each UDC's existing balancing accounts.[31] With the existing

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[29] SDG&E would use its existing "Adjustment to Electric Distribution and Gas Margin Rates" mechanism. Each year's recorded capital cost and associated depreciation cost will be recovered in the subsequent year via an annual advice letter filing in October each year and subsequent rate changes effective January 1 of the following year.

[30] For SDG&E, these payments would be recorded directly in SDG&E's Energy Resource Recovery Account (ERRA) balancing account authorized in D.02-10-062. The ERRA describes the process to recover over/under collections. If the Commission authorized programs involve utility "capacity" incentive payments, then these payments will be estimated by the utility and recovered through ERRA. The actual "capacity" incentive payments will be recorded in the ERRA balancing account and reconciled with the actual revenue collected and recorded and adjusted in the subsequent year's revenue requirements

[31] For PG&E, the current Emergency Procurement Surcharge Balancing Account (ESPBA) and the Transition Revenue Accounting (TRA) mechanisms record procurement costs including retained generation costs. Additionally, the current TRA mechanism ensures that full collection of PG&E's authorized distribution, nuclear decommissioning, and public purpose program revenue requirements will continue even if changes in usage patterns from demand response programs produce revenue under-collections of the type described here. PG&E will seek similar accounting mechanisms once the TRA is no longer in place.

For SDG&E, a material change in T&D under collections will trigger SDG&E to file an advice letter to create a T&D regulatory account to track under collections resulting from R.02-06-001 demand responsiveness programs. Currently, SDG&E does not have a mechanism for distribution revenue under collections from authorized levels.

balancing accounts, the UDCs believe it is unnecessary and, in fact, burdensome, to formally track costs and revenue shortfalls by tariff option/program, i.e., assuming the same level of sales, revenues received under the new tariff compared to revenues that would have be received under the otherwise applicable tariff.

Table 10 shows the 2003 estimates[32] of the incentive payments and revenue shortfalls associated with WG2 demand response programs and pilots as used in the cost-effectiveness analysis.[33] These estimates depend on number of customers, amount of demand reduction, and several other factors and, therefore should be treated as rough approximations.

TABLE 10: 2003 Estimated Incentive Payments and Bill Changes For WG2 Demand Response Programs and Pilots[34]

Proposer	Program Name	Estimated Incentive Payments	Estimated Energy Bill Changes	Total
ACWA	CPP	$5,150,000	$3,855,000	$9,005,000
CPA	CallOp	$8,600,000	$3,600,000	$12,200,000
CPA	NonSpAS	$7,900,000	$1,800,000	$9,700,000
CPA	SupEn	$8,100,000	$270,000	$8,370,000
CPA	ISO Credit	$1,000,000	$4,000,000	$5,000,000
Infotility	TPRTP	$2,500,000	$0	$2,500,000
IMServ	CP T&D	$1,850,000	$450,000	$2,300,000
PG&E	RTP/CPP	$0	$13,000,000	$13,000,000
PG&E	DBP	$173,000	$0	$173,000
SCE	RTP-MI	$0	$597,000	$597,000
SCE	DBP	$597,000	$0	$597,000
SDG&E	DBP	$8,000	$3,000	$11,000
SDG&E	HPO	$0	$426,000	$426,000
TOTAL		$35,878,000	$28,001,000	**$63,879,000**

For SCE, these payments would be recorded in the Procurement Related Obligations Account (PROACT). This mechanism assures full collection of SCE's authorized distribution, nuclear decommissioning, and public purpose program revenue requirements will continue even if changes in usage patterns from demand response programs produce revenue under collections of the type described here. SCE will seek similar accounting mechanisms once the PROACT is no longer in place.

[32] Some estimates could include some 2002 expenditures.

[33] The IMServ proposal was not included in the cost-effectiveness analysis as the data was not available.

[34] The "Incentive" payments on the CPA program and IMServe program are actually commodity procurements from DWR or from the IOUs. At least some procurements (e.g., ISO credit, transmission) will need to come from the IOU procurement rather than DWR procurement.

V.B.1.(f) Cost Incurred Prior to Commission Decision Authorizing Expenditures for R.02-06-001

As discussed above, WG2 recommends the Commission authorize the UDCs to record WG2 demand response program and pilot costs incurred prior to a Commission's Phase I decision in a sub account of the AMDR Account. The costs that would be recorded should be expanded to include all reasonable advance lead-time activities needed to continue to develop the WG2 tariffs and programs and the WG3 statewide pilot before the Commission issues its decision in Phase I. These costs would be capped at $1 million for all three UDCs combined ($450,000 for PG&E and SCE respectively, and $100,000 for SDG&E). In other words, in addition to the prerequisite market research needed for both Working Group 2 and 3 demand response programs and pilots, the UDCs would also seek to record the costs of various activities that of necessity are going to need to be continued over the next three months. These include: development of information, technology, and rate treatments; sample design; and any other activity needed to continue to refine and implement the pilot and tariffs to ensure that they have a reasonable chance of being in place by the summer of 2003. The UDCs anticipate that in its Phase I decision, the Commission will authorize expansion of the proposed balancing account to include further implementation costs.

V.B.1.(g) Language Required in Commission Ruling Authorizing Establishment of the AMDRA

WG2 recommends the following language (implementing the above concept) be included in a Commission Ruling authorizing the UDCs to establish these accounts. This level of detail is necessary for the UDCs to be in a position to quickly file uniform, complying advice letters:

> "The utilities shall each file advice letters establishing Advanced Metering and Demand Response Balancing Accounts (AMDRAs). The purpose of the AMDRAs is to record and recover the incremental, one-time set-up and on-going Operating and Maintenance (O&M) and Administrative and General (A&G) expenses incurred to implement, or in reasonable anticipation of implementing, the demand response programs adopted by the Commission in R. 02-06-001. These costs would be limited to a total of $1 million for the three utilities combined ($450,000 for PG&E; $450,000 for SCE; and $100,000 for SDG&E) of costs incurred until the Commission issues its Phase I decision in this proceeding and approves an accounting mechanism for additional expenditures necessary to implement its decision. The AMDRAs will apply to all customer classes, unless the Commission specifically excludes any class. The revision dates applicable to the AMDRAs shall be as determined in each utility's annual advice letter filing or as otherwise ordered by the Commission. The AMDRAs will not have a rate component. The utilities shall maintain their respective AMDRAs by making entries at the end of each month as follows:

A debit entry equal to the utility's incremental one-time "set-up" and on-going O&M and A&G expenses for advance lead-time work necessary in anticipation of implementing WG2 demand response programs and pilots.

A credit entry equal to the interest on the average of the balance at the beginning of the month and the balance after the above entry at a rate equal to one-twelfth the interest rate on three-month Commercial Paper for the previous month, as reported in the Federal Reserve Statistical Release, H.15 or its successor."

V.B.1.(h) Process to Establish the Accounts

WG2 and the UDCs propose that the following steps be followed to establish the AMDRA:

- Ruling issued directing the UDCs to each file advice letters within five business days (assumes that the ruling contains language as comprehensive and detailed as that specified above)
- Parties have 10 days to comment on advice letters
- Advice letters become effective retroactive to the date of filing upon written approval of the Energy Division (does not contemplate resolution or CPUC decision).

METHODS OF VENDORS COST RECOVERY

VENDORS are not regulated by the Commission, and therefore require a somewhat different cost recovery mechanism than the UDCs joint cost recovery proposal. Funding for VENDORS reasonable expenditures on authorized WG2 demand response programs and pilots could be through contracts with the UDCs, funding through the CEC's PIER, or through the CPA's Public Goods Charge. Since several options are available, the Parties are encouraged to address this issue more specifically in their December 30 comments to this report.

Also, reasonable VENDOR costs associated with various going forward activities need to be recovered, such as, development of information, technology, and rate treatments; sample design; and any other activity needed to continue to refine and implement WG2 demand response programs and pilots to ensure a reasonable chance of being in place by June of 2003.

WG2 recommends that any Vendor funding for WG2 demand response programs and pilots include a contracting mechanism[35] with the UDCs through authorized balancing accounts.[36] WG2 believes that demand response

[35] Prime contractor or Subcontractor.

[36] AMDRAs.

programs and pilots could be categorized as energy efficiency programs and therefore, could be funded through the CEC's PIER. Similarly, the CEC's Public Goods Charge could be used to fund VENDOR cost recovery. The CPA's DWR mechanism for demand reserves and demand response is slightly different from the CEC's PIER because those programs are viewed as procurement just like the purchase of power from a combustion turbine, so the cost recovery for the CPA programs comes from the commodity accounts of the UDCs. WG2 agrees, that as long as the Commission continues to fund the DWR revenue requirement or demand response through utility commodity procurement, such a recovery mechanism is reasonable.

VI. PILOT PROGRAMS

The topic of pilots received limited attention until late in the WG2 process. The ALJ Ruling of September 5 directs WG2 to address the extent to which existing pilots should be reshaped to meet the needs for assessment of dynamic pricing tariffs and programs. As WG2 discussed various tariff and program proposals, uncertainties about customer response to various incentive structures became very clear. In some respects participants began discussing these proposals as though they were pilots rather than “production programs.” When WG2 determined that a delay in the schedule was necessary, the internal schedule segregated discussion of pilots to the second WG2 report. Pilot proposals were discussed explicitly in the meetings of November 19 and December 2.

Two pilot proposals were raised during WG2 discussions. IMServ-Invensys originally proposed a tariff that focuses on achieving transmission and distribution (T&D) benefits, but agreed to withdraw this proposal as an actual production tariff and instead submitted it later as a proposed pilot. Infotility proposed a pilot to evaluate various real time pricing (RTP) baseline and customer information issues. Both pilot proposals were discussed in detail at the December 2 meeting, with both receiving extensive criticism from meeting participants. As a result, different outcomes resulted for each pilot proposal. IMServ-Invensys persisted in making its pilot proposal, which is described below in section VI.A. Infotility was willing for its proposal to be further considred in the followup WG2 development of a two-part RTP tariff. Although not included as a pilot proposal supported fully by WG2 participants, the possible need for a pilot to test RTP tariff design elements is acknowledged by WG2. A brief discussion of how WG2 proposes to address the potential need for a pilot is included as section VI.B.

VI.A. Constrained T&D Peak Capacity Proposal (TDC) by IMServ - Invensys

This proposal is submitted by Invensys – IMServ (IMServ). IMServ’s products and services center around collecting and providing advanced energy information, including settlement services to utilities, ESPs, ISOs, SCs and customers as well as providing metering services.

GENERAL DESCRIPTION

Peak energy constraints include generation as well as capacity constraints on transmission and distribution systems. Constraints on the T&D system can be as serious as those for generation.

Unfortunately, it is likely that the curves for peak generation and peak T&D constraints do not coincide. In addition, direct access customers appear to be an untapped resource in addressing peak T&D energy constraints. And while peak generation issues are addressed by a number of proposals, T&D and direct access customers have received only limited attention.

Similar to energy efficiency programs, customers should receive financial benefits in reduced T&D charges when they take actions that produce benefits on constrained T&D systems. The TDC program proposes an integrated T&D demand response system employing advanced metering and customer specific operational controls directed towards reducing demand on constrained transmission and distribution systems. To minimize costs, maximize asset usage, provide increased flexibility and high operational standards, the full scale advanced metering system will be CPUC – PSWG compliant and also be available for metering for direct access billing purposes. Utility T&D credits for those customers who reduce constrained T&D costs would be proposed by the local utility and approved by the CPUC.

The advanced metering solution for direct access customers will offer an technically advanced open architecture system that will enable customers, and authorized firms such as ESPs, MDMAs, utilities and others to directly access energy information, on demand, from the meter, through a server or through web based applications.

The program will compliment that of some other proposed projects and also fill in gaps in the customer offering. Features include:

- wider end user customer participation, including direct access customers

- focus on reducing T&D system energy constraints, T&D constraints may not coincide with critical peak generation

- focus on developing sufficient information for a full scale phase 2 effort that will feature CPUC – PSWG compliant open architecture meters that could be accessed through multiple technologies such as a radio and telephone at the meter

- C&I customers have previously commented they prefer to select their own approach to delivering demand responses and it is the intent of this program to respond to this customer concern. As such, TDC will not focus on any particular technology as a solution, but is customer specific. Solutions can range from advanced metering with advanced web based information and feedback systems to advanced automated facility load controls coupled with advanced meters and information systems.

- Incentives will be based on two levels: a.) a base load shift, e.g. installing systems or changing operations to reduce peak demand on a long term basis, b.) responding to demand reductions on a as requested basis

The TDC proposal compliments other proposed programs such as CPA'a Demand Reserve Partnership program. To the extent these various programs are complimentary, systems such as advanced metering and controls might be able to be used in both programs and as such presents a potential for cost efficiencies. For direct access customers and bundled utility customers, the implementation mechanism of TDC would be through the CPA's Transmission Pilot Program.

A phase 2 effort will include:

- open architecture metering systems with optional advanced controls
- CPUC - PSWG compliant advanced meters
- for DA customers, integrated meter reads by certified MDMAs
- when possible, to reduce costs, use existing advanced meters, if applicable and if PSWG compliant

An advanced metering system combined with advanced demand response controls can provide the needed customer flexibility, information systems and facility controls to enable customers to better respond during periods of high peak T&D demand. The benefits of this will help constrained T&D systems and enable energy suppliers to provide additional energy supplies through formally constrained systems.

For the phase 2 effort, installation and metering services would be competitively provided by certified MDMAs for DA customers, subject to customer approval. Metering systems for the full scale program would be those prescribed under the CPUC's PSWG report; if necessary, the report would be updated to reflect the latest technology advances. To provide maximum customer flexibility and not lock a customer to any particular vendor, meters selected will be those that can be adopted to either a telephone or radio based communication system.

This proposal provides four key benefits that the CPUC asked WG2 to consider (ALJ Ruling, dated October 2, 2002, pg 9):

- Avoided T&D upgrade costs
- Benefit of net reduction in air emissions (and other environmental externalities) - with reduced congestion and reduced constraints on a local T&D system, there may be less of a need to employ costly local peaking units since power outside the local area will be able to be imported into the area
- Value to customers of more timely and accurate information about electricity use
- Lower customer electric bills

HOW RESULTS WILL BE USED IN PHASE 2 AND BEYOND

Results from the proof of concept test will be used to establish cost/benefits for a phase 2 effort including: expected T&D constrained demand reduction, program costs, customer preferences and interests in participation, value of providing only information to a customer versus investing in additional facility controls. During phase 2 ,meters that were recently certified as CPUC-PSWG could be introduced.

COSTS OF PILOT VS EXPECTED DOLLAR OR OTHER BENEFITS

The cost of the pilot will be controlled by the to be determined cost benefit ratio of program cost to expected benefits. T&D benefits will need to be developed by the local utility. The amount of money to be invested for a customer will be based on the expected T&D benefit and the required cost benefit ratio. For instance, if the required T&D benefit ratio is $300/kW and the customer has a potential to reduce T&D demand by 100 kW, then the limit for costs or incentives to the customer would be $30,000 under the phase 2 . If the customer already has a suitable advanced metering system, then efforts will be made to use that system; thus a potential for cost savings in the program. Although we have not engineered a typical system, but based on the results of the CEC +200 kW meter program, an advanced meter with a web based customer information system could cost $1,000 to $3,000 for a C&I customer with operating costs and controls additional.

DETERMINATION OF THE CUSTOMER’S LOAD REDUCTION

(Note – A portion of this section is taken from the UDC Joint Utility - Demand Bidding Program Proposal Dated October 31, 2002 and submitted to Workgroup2)

For a short term T&D demand reduction, In order to determine how much T&D the customer actually reduces, the MDMA, Utilities, or ESP must know what the usage would have been before the customer reduces. This Customer Specific Energy Baseline (CSEB) is this 10-day rolling average energy usage determined on a hourly basis, using the average of energy usage for the same hour for the past 10 similar days (excluding days the customer was paid to reduce power under the demand response program or the customer was subject to a rotating outage) prior to a event. The customer’s CSEB is compared to the actual amount of kW used for that hour during the DBP Event to determine if the customer complied with the program and if the customer is eligible for the bill credit.

For a longer term, demand load shift, such as creating a new work shift to reduce load or scheduling work for non-critical T&D periods, the customer would present a proposal and if approved the customer would receive the lower T&D charge for the period of constrained demand. This approach is similar to what was done through past utility customized energy efficiency rebate programs. The customer must have interval metering capable of recording usage in 15-minute intervals and Internet access.

TARGETED PARTICIPATION

Electric Customers who are in T&D constrained areas. This applies to customers above and below 200 kW, there is no size limit for the program. Customers, in addition to direct access customers, would be eligible to participate. Aggregation would be acceptable.

The target market will include both direct access customers and utility customers. Customers will be from those geographic areas where there are critical T&D constraints. Further information on these locations will need to be provided by the utilities. DA and utility customer participation in the proposed T&D peak constraint programs would be voluntary with an opt in/out provision.

A diversity of types of customers, climate zones and T&D congestion points will be needed for the initial proof of concept test. Customers will include those above and below 200 kW. We anticipate that 1,000 - 5,000 customers, throughout California to be included in the pilot. Participation would be voluntary. Subject to prior approval, DA customers would choose their metering system and control solution. For DA customers, these same meters would be used for billing purposes and would be read by certified MDMAs.

DA customers would be recruited by marketing efforts through participating ESPs and notices sent by their serving MDMA. Non DA customers would be recruited through efforts similar to those that the UDCs will use to recruit customers for their critical peak pricing programs.

REQUIREMENTS TO PARTICIPATE

Electric customers who are in T&D constrained areas.

VI.A.6.(a) Source of Drivers/Triggers

Drivers and triggers include minimizing the adverse impact of constrained T&D systems, including costs associated with upgrading these systems and the environmental impacts of having to run peaking units in transmission constrained areas.

Customer incentives will be designed to provide positive TRCs and to be less than the cost of upgrading a transmission sector.

The $/kw incentive is not yet determined and would be based on numbers supplied by utilities. But assuming an incentive of $100/kW reduced and if 100 kW of load is reduced, the total incentive to the customer would be less than $10,000.

INTENDED LEVEL OF PARTICIPATION

The TDC program compliments other proposed programs and tariffs. End users can participate in other programs and tariffs, however, double counting of benefits is not allowed. The extent of participation in the pilot will be limited by its market size and available budget. We anticipate a minimum of 1,000 customers for the pilot.

SOURCES/LEVELS OF COSTS INCLUDE:

- Program design and development, including administration, market research, marketing, information system development.

- Program operation, including advanced meters, web information systems, customer specific load control systems or cash incentives. Note: some customers may already have suitable advanced meters and so they may not need new meters, other customers may already have sufficient demand response technologies installed and so they may only require advanced meters, communication systems and web access.

METHOD OF COST RECOVERY

Long run program costs will approach revenue neutrality since the emphasis of the program is to cost effectively reduce congested T&D costs. Some customers may also participate in other critical peak programs, such as the proposed California Demand Reserves Partnership, and so some program equipment might overlap some of these programs and could be combined. Cost recovery would be through reduced long run T&D costs. Additional funding sources would be similar to that proposed by other programs from Working Groups 2 and 3, other example of funding sources would be similar to that used for energy efficiency programs. With CPUC approval of the program concept, founding sources would need to be finalized before program development costs are incurred.

ESTIMATED START DATE

For a "quick win" approach, with CPUC approval in February, 2003, marketing would begin in March 2003 and proof of concept operation would begin in June 2003. Based on results of the proof of concept the program would be expanded for maximum coverage in the summer of 2004.

The Commission should note that this effort requires initial engineering and development expenses to develop the program and its needed systems. These investments are not likely to occur until after the CPUC has approved the basic program concept and parameters.

METHOD OF IMPLEMENTATION

Key points are:

- The implementation mechanism of TDC would be through the CPA's Transmission Pilot Program. Metering and performance monitoring of participating direct access customers would be by certified MDMAs, with the cooperation of the ESP, Scheduling Coordinator and local utility.

- Utilities would identify constrained T&D areas and would identify cost effective incentives/rebates for reducing T&D constraints. These rebates would be subject to CPUC approval.

- MDMAs and ESPs would market the program to direct access customers. Only those direct access customers whose contracts with their ESP permit such participation would be eligible.

- MDMAs would be responsible for calculating customer T&D reductions.

IMPLEMENTATION PLAN:

- receive CPUC approval of concept and funding sources
- develop additional program analysis and details, including T&D benefits, assign staff
- develop program rules and procedures
- develop necessary back office systems for phase 1
- begin marketing
- begin actual installations
- evaluate results
- based on positive results, proceed to wide scale program deployment.

LEAD TIME FROM APPROVAL

As previously noted, for a "quick win" approach, with CPUC approval in February, 2003, marketing would begin in March 2003 and proof of concept operation would begin in June 2003. Based on results of the proof of concept the program would be expanded for maximum coverage in the summer of 2004.

OTHER IMPLEMENTATION ISSUES

- Since the utilities are the source of information on locations, numbers of customers, extent of T&D constraints and potential costs and benefits, we have not attempted to estimate these. However this information is critical before proceeding with detail program design and implementation.

- The commission should note the work done on developing this concept has been pro bono, rate payers have not funded the concept development. While additional work needs to be done prior to launching the pilot, this work cannot afford to be done without approval of the concept by the CPUC.

- For this T&D effort to be successful, the support and cooperation of utilities, CPA and direct access related firms is essential.

VI.B. Potential Usefulness for an RTP Pilot

WG2 found that it could not submit a two-part RTP tariff proposal on the schedule necessary for Phase 1 of this proceeding. WG2 requested, and an ALJ Ruling of November 13, 2002, relieved WG2 of its obligation to submit such a tariff proposal. This Ruling, however, required WG2 to submit a proposed schedule for development and implementation of a two-part RTP tariff. WG2 provided its proposed schedule in its November 15, 2002 report.[37] Essentially, WG2 proposed to resume discussions about two-part RTP tariff designs in early January 2003, to develop a firm schedule for development of a tariff, and to work toward accomplishing preparation of a final proposal for implementation by October 2003, presuming Commission approval in a timely manner.

Infotility presented a draft of a pilot proposal at November 19 meeting, and a more refined version at the December 2 meeting.[38] As a result of the discussion of the Infotility pilot proposal, WG2 agreed that testing alternative design features of a two-part RTP tariff may prove useful. WG2 believes that market research and pilots testing these alternatives may result from the deliberations that it will undertake beginning in January 2003. WG2 wants WG1 to understand that this possibility exists, and requests that cost recovery and a mechanism to achieve expedited approval of such requests be explicitly acknowledged in the forthcoming Phase 1 decision.

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[37] WG2, Report of Working Group 2 on Dynamic Tariff and Program Proposals, November 15, 2002. See section V.G, pp. 92-94.

[38] The December 2, 2002 version of the Infotility pilot proposal is included as Appendix C.

An RTP pilot could test one or both of two different perspectives concerning an RTP tariff. First, a pilot could test various design features of the tariff itself. For example, alternative baseline computations might influence participant demand response as the tariff operates as well as whether customers are willing to voluntarily signup for the tariff. The results of the pilot would be used to determine the final design recommendations. Second, a pilot could test various customer information distribution and display support tools that might reveal differential levels of demand response to price signals. The results of such a pilot might lead to decisions about different levels and types of customer education and support, with potential impacts on UDC costs of implementation. WG2 could decide to test one or both of these elements of the overall two-part RTP package.

If WG2 recommends testing two-part RTP tariff design features during 2003 through a pilot, this decision could lead to a delay in the submission of a final tariff proposal and a delay in the date the tariff would become operational. On the other hand, a test of various information display and decision-making aides that do not affect the design of the tariff itself might not delay the implementation date.

WG2 proposes the following mechanism for the treatment of a potential RTP pilot:

a. In the Phase 1 decision, the Commission should authorize expenditures for two-part RTP market research and pilot costs up to $2 million dollars;

b. Actual costs of such market research and pilots would be recorded and recovered using the same UDC rate making mechanisms authorized for WG3 pilot activities;

c. An UDC request to implement a pilot for a two-part RTP tariff design, endorsed by WG2 (and/or appropriate successor bodies), would be treated as a compliance advice letter by the Energy Division and given expedited approval treatment.

d. WG2 participants (and/or appropriate successor bodies) would be provided periodic informational reports and access to pilot results by the implementing UDC, under standard confidentiality protection arrangements for the participant interval load data and other sensitive information.

VII. RECOMMENDATIONS AND NEXT STEPS FOR PHASE 2

This section addresses recommendations for decisions to be made about the proposals in a phase 1 decision, and in next steps that should be considered for phase 2 of this proceeding.

VII.A. Phase 1 Recommendations

WG2 makes the following recommendations concerning the marketing and education, cost-effectiveness assessment, monitoring and evaluation, and cost recovery activities described in this report.

MARKETING AND CUSTOMER EDUCATION

1. Marketing/Customer Education should be coordinated across all utilities and non-utilities, to the extent feasible, to make it as easy for the end use customer as possible.

2. To the extent the Commission desires higher participation in the large customer tariffs than the expectations listed in Section III, the Commission should consider additional customer participation incentives or other means of increasing participation.

RELIANCE UPON COST-EFFECTIVENESS ASSESSMENTS

Because the existing Standard Practice Manual cost-effectiveness tests may not be directly applicable to the evaluation of dynamic pricing tariffs and other market-response programs, the Commission should be cautious in interpreting the results of such tests until after improvements in these tests have been developed and accepted by the Commission and California Energy Commission.

MONITORING AND EVALUATION

1. The Commission should adopt the concept of a comprehensive M&E plan as described in section II.C and authorize cost recovery for such an effort. The UDCs and regulatory agencies should be directed to develop a full and complete M&E plan by May 1, 2003. The monitoring elements of the evaluation should be in place in time to help refine the program offerings and information provided to potential customers, and to provide feedback on potential program changes based on initial customer reactions. The impact evaluation should be completed and submitted to the Commission in the Fall 2004, which would result in recommendations for changes in dynamic tariffs or programs being reviewed and decided in late 2004 or early 2005 for actual implementation beginning Spring 2005.

2. The Commission should adopt an ongoing monitoring and evaluation approach regarding all demand response programs. The monthly reports for the interruptible programs now filed pursuant to Ordering Paragraph 8 and Appendix F of Decision No. 02-04-060 should be expanded to include the

programs approved in this proceeding. These monthly reports should also highlight any unusual activities or needs for review for these programs.

COST-RECOVERY

The Commission should approve the recovery of reasonable costs as described in Section VI.B for each of the programs, and joint costs across multiple programs, approved in this proceeding using the standards established in D.01-04-006.

FUTURE DEMAND RESPONSE PROCEEDINGS

The Commission should establish a decision-making forum to review and revise demand response tariffs and programs in later 2004 and early 2005 to ensure that monitoring and evaluation results are considered when demand response programs and tariffs are authorized and implemented for summer 2005.

VII.B. Next Steps for Phase 2

The ALJ Ruling dated September 5, 2002 directs WG2 to include within the scope of its activities recommendations for next steps to be addressed in Phase 2 of this proceeding. WG2 has identified the following topics that would improve tariffs and programs for application with customers >200 kW, and which will not be resolved in the timeframe of the Phase 1 decision. Some of these activities have not been addressed in Phase 1, and their importance has been realized during the course of WG2's activities. Others involve implementation and/or monitoring of Phase 1 activities as they are authorized in phase 1. WG2 is unsure whether to classify these as Phase 2 activities, but they are nonetheless important.

In Phase 2, WG2 recommends that the following activities be organized and resolved, as far as possible, through working groups and workshops. It is likely that for some topics more formal Commission mechanisms will be required to resolve the remaining disputes among parties once workshops and working groups complete useful discussions.

INCORPORATING DEMAND RESPONSE INTO UDC PROCUREMENT

D.02-10-062 directs the three UDCs to encompass demand response programs and tariffs within the short term and long term procurement plans that are to be filed with the Commission. The November 12, 2002 short term filings and the responses filed November 26, 2002 to the procurement questions raised in the Assigned Commission ruling of November 13, 2002 raise numerous questions about the practical issues of including demand response within procurement plans and about the ability of UDCs to effectuate a "level playing field" assessment of demand and supply options.

The Commission should create a mechanism so that the procurement activities underway in R.01-10-024 and the demand response development activities underway in this rulemaking are more completely coordinated. WG2 recommends that R.01-10-024 explicitly delegate to Phase 2 of R.02-06-001 creation of demand response accounting conventions, mechanisms to compare and contrast supply and demand options, and creation of appropriate coordination with the CAISO to support substantial reliance upon demand response as a strategy for UDC bundled service procurement. These Phase 2 methods would be included within R.01-10-024 at a point in late spring or early summer as part of the development of a long term procurement decision that would guide UDC procurement decisions in 2004 and beyond.

REFINEMENT OF THE C/E TESTS WITHIN THE STANDARD PRACTICE MANUAL

In the course of attempting to conduct cost-effectiveness tests for the tariffs and program proposals contained in the WG2 reports, WG2 has encountered difficulties with both the Standard Practice Manual (SPM) tests themselves and in ascertaining appropriate input assumptions for some key variables. A description of these difficulties is contained in section V.D of this report.

WG2 recommends that Phase 2 of this rulemaking create a working group process that would be charged with modification of the existing Standard Practice Manual tests and procedures for obtaining input assumptions that would overcome most or all of the SPM deficiencies identified in this report. A proposed SPM revision by this working group would be subjected to a comment opportunity prior to being jointly adopted by the Commission and the California Energy Commission.

VII.B.3 Examining Need for and Developing DR Tariffs and Programs to Mitigate Locational Marginal Price Consequences

The ALJ Ruling dated 10/2/2002 directed WG2 to consider transmission and distribution benefits in the design and cost-effectiveness assessment of dynamic tariffs or programs, but WG2 did not have time to address this topic in depth. Further, the detailed data concerning transmission congestion prices or hourly patterns of distribution costs was not available to WG2 participants. Transmission congestion assessments and transmission pricing are under the jurisdiction of the CAISO and the Federal Energy Regulatory Commission. Thus WG2 is unable to provide proposed tariffs or programs that respond to these concerns.

WG2 believes that greater coordination among agencies is needed before setting out to design dynamic tariffs and programs responsive to these concerns. Once such coordination is in place, then a working group process may be a useful mechanism to design such tariffs and programs and to assess their prospects for acceptance among end-users.

Appendix A: List of Primary Authors

Report Section/Subsection	Author	Organization
Executive Summary	B. Kaneshiro	CPUC
I. Introduction		
A. Mission for >200 kW Customers	B. Kaneshiro	CPUC
B. Nature of the Working Group Process	B. Kaneshiro	CPUC
C. Role of this Report	B. Kaneshiro	CPUC
II. Fundamental Considerations		
A. Customer Marketing and Education	C. King	eMeter
B. Customer Education Proposal	S. Sides	SDG&E
C. Monitoring and Evaluation Plan	M. Jaske	CEC
III. Specific Marketing, Customer Education, Monitoring, Evaluation Plans		
A. PG&E Proposal	D. Evans	PG&E
B. SCE Proposal	D. Reed	SCE
C. SDG&E Proposal	S. Sides	SDG&E
D. ACWA Recommendations	L. House	ACWA
E. CPA Recommendations	J. Flory	CPA
IV. Cost Effectiveness Analysis		
A. Description of Framework	S. Anderson	Power Value, Inc.
B. Assumptions and Inputs	S. Anderson	“
C. Results	S. Anderson	“
D. Issues for Cost-Effectiveness Analysis	S. Anderson/C. Silsbee	Power Value, Inc./SCE
V. Generic Implementation Issues		
A. UDC Back Office Capabilities	E. Wong, L. Low, P. Borkovich	PG&E, SCE, SDG&E
B. Cost Recovery	C. Blunt	ORA
VI. Pilot Programs		
A. IM-Serv-Invensys Proposal	G. Lizak	IMServ-Invensys
B. Potential Usefulness for an RTP Pilot	M. Jaske	CEC
VII. Recommendations	All WG 2	
APPENDICES		
A. List of Authors	B. Kaneshiro	CPUC
B. Meeting Minutes	B. Kaneshiro	CPUC
C. Two-Part RTP Pilot Proposal	J. Desmond	Infotility
D. Cost-Effectiveness Input Data	S. Anderson	Power Value, Inc.
E. SCE RTP Customer Profile	M. Collette	SCE
F. SDG&E HPO Illustrative Bill Impacts	P. Borkovich	SDG&E

APPENDIX B: Meeting Minutes

Working Group 2
November 19, 2002 Meeting Minutes

I. Getting Oriented

Seven handouts were provided: meeting agenda, PG&E Overview of Marketing and Customer Education For the Joint IOU DBP and PG&E's RTP/CPP Proposal, SCE's RTP-MI Implementation Schedule and Demand Bidding Implementation Schedule, SDG&E's Preliminary Customer Education and Marketing Plan for Hourly Pricing Option, email sent by Andrew Bell (PG&E) to Stan Anderson regarding Cost-Effectiveness Inputs (dated November 18, 2002), Draft Pilot Proposal from Infotility for a Two-Part RTP Program, and Draft of the December 13 Report Outline and Author Assignments. The last two items were circulated after lunch.

A brief discussion of the November 15 report filed with the Commission revealed that some small imperfections had been discovered, and that preparing and filing an errata might be advisable.

II. Marketing and Customer Education

PG&E presented an overview of it marketing and customer education plan for both the Demand Bidding and RTP/CPP proposals. PG&E will use a combination of brochures, Internet promotion, account representatives, and its Business Customer Center (BCC) to market the programs. PG&E also indicated that it is currently developing an 'energy rate tool' that could be used to help customers decide if the programs work for them. It is not known yet if this tool will be accessible by customers, or be managed only by PG&E staff. PG&E acknowledged that it would be able to market its programs to customers who have already received CEC funding for demand response. PG&E noted that of 8,200 accounts that are above 200 kW, approximately 2,800 have account representatives. Those accounts that do not have an assigned account representative can get information via PG&E's BCC staff.

SCE proposes to follow a strategy similar to the one proposed by PG&E. SCE has account representatives for approximately 5,000 of the 10,000 accounts that are above 200 kW.

SDG&E proposes to follow a marketing strategy similar to that proposed by PG&E and SCE, although SDG&E noted that their concept of customer education may focus on translating the effect of new programs/tariffs in terms of customers' operational costs, in addition to bill impacts. SDG&E reported that it has 2,500 customer accounts above 200 kW, of which approximately 500 are potential participants for its proposed HPO tariff. SDG&E suggested distinctions between marketing and customer education, and that costs each of these categories of activity might be collected in different ways.

WG 2 discussed possible roles of third parties in marketing new programs. The CPA noted that demand reserve providers have expressed interest in doing cross-marketing of the IOU programs if 'finders fees' could be arranged. One issue associated with finders fees is determining who gets the credit for a sign-up if the customer approaches both the IOU and the third party for information. Another issue with using third parties to market IOU programs is that third parties have different interests from the IOUs, and will thus market the programs with a different emphasis. IOUs noted that they make efforts to coordinate their marketing plans with known third parties who may also be marketing their programs.

WG 2 discussed any linkage between intensive customer education/marketing efforts and increases to program signups. The IOUs noted that increased funding for customer education/marketing does not necessarily translate into more signups, but that customer interest in programs relies more upon the customer's perceived value of the program itself. Thus, IOUs noted that customers are more responsive to direct incentives that increase value of participation. Therefore, developing a range of estimates based on marketing and customer education efforts may not be fruitful, and if the Commission were interested in a "lever" to increase participation that direct or indirect incentives would be a more useful tool. Customer representatives noted that the programs should avoid too much emphasis on the industrial customers because many of them are already operating at their highest efficiency.

WG 2 also discussed that the notion that marketing efforts for these new programs will have to consider potentially conflicting messages of the desirability to sign-up for new programs and the stability of the energy market.

III. Developing Ranges of Estimates

WG 2 participants discussed this topic in the context of its marketing/customer education efforts, and in the cost-effectiveness analysis (Section IV).

IV. Conducting Cost-Effectiveness Tests for Each Proposal

Stan Anderson provided an update on the cost-effectiveness analysis. As agreed at the November 12 WG 2 meeting, Anderson distributed a data input format to WG 2 on November 14, 2002. To date, Anderson has received only one substantially complete response (from the CPA), although he noted that all of the other proposal proponents are working on their data inputs in good faith.

WG 2 participants focused on the questions raised in PG&E's email back to Anderson. WG 2 participants agreed that their inputs to Anderson should be a reflection of those customers they believe would participate, and that a range of responses would be helpful. For example, PG&E anticipates providing responses ranging from 5% to 20% for its program. After discussion it was agreed that a range of response based on assumed elasticities was a more useful descriptor of uncertainty than numbers of participants.

WG 2 also received unofficial word that it was important to stay on schedule and deliver the 2nd report on time (December 13), meaning that WG 2 should reduce the scope of the cost-effectiveness analysis if that causes a slippage to the report delivery date.

Anderson noted that if the proponents can deliver their cost-effectiveness inputs to him by close of business Friday, November 22, he can still deliver preliminary results in time for discussion by the next WG 2 meeting on December 3**.** Delays in providing the inputs will necessarily create a slip in Anderson's schedule to provide the results. Anderson indicated that if complete inputs were received by 11/22 that he could provide preliminary C/E assessment results by COB 11/25. If inputs were delayed, then a day for day delay in delivery of results should be expected.

It was agreed that review of the proposed 11/25 preliminary C/E assessment results would occur at the 12/3 WG2 meeting, and that additional C/E assessment might be required before considering them final.

V. Monitoring and Evaluation Plan

WG 2 discussed this topic in general, with the IOUs emphasizing that 2 to 3 years of data would be necessary to do an adequate evaluation of the programs. WG 2 discussed whether these programs would be evaluated after only one year, and possibly terminated. Many participants felt that termination after only one year would be detrimental. No one was opposed to monitoring and data gathering for the new program/tariffs. Some discussion emerged about specific data that would be relevant to monitor such as participation numbers and costs, as well as data that tracks behavior changes and amounts of load that have been curtailed or shifted. Specific monitoring and evaluation plans will be discussed at the next WG 2 meeting.

VI. Pilots for > 200 kW Customers

The IMServ- Invensys pilot proposal was not discussed, as there was no representative present.

J. Desmond from Infotility requested an opportunity to present a pilot proposal for a two-part RTP program that could be implemented by June 1, 2003. There was considerable debate as to whether the proposal should be presented as some participants argued that WG 2 had already agreed in previous meetings that two-part RTP programs would be addressed in 2003, with an implementation target of October 2003. Desmond was allowed to make his presentation in light of WG 1's expressed interest in two-part RTP programs, and WG 2's assignment to consider pilot programs for next year.

WG 2 participants were advised to review the handout provided by Desmond, and be ready to discuss the proposal at the next WG 2 meeting. WG 2 will specifically decide amongst the following options: a.) include Infotility's proposal in the December 13 report, b.) not include the proposal in the December 13 report, but enfold its concepts into the two-part RTP process in 2003, or c.) dismiss the proposal altogether.

VII. Wrap Up and Review

WG 2 reviewed a draft outline for the December 13 report to determine how the sections should be organized and assignment of authors to write them. Attached to these minutes is an updated draft outline based on the discussion. Please take note of the specific footnotes in the updated outline as these reflect relevant details that were discussed.

- Next meeting is set for December 3, at the CPUC (either the Auditorium or Hearing Room A).
- Proposal proponents should be prepared to discuss specific monitoring and evaluation plans on December 3.
- Proposal proponents should provide to Stan Anderson their data inputs for the cost-effectiveness analysis by Friday, November 22.
- CPUC/CEC staff will circulate a template to be used by proponents of proposed pilots for the December 13 report.
- Assigned authors should have their write-ups distributed to WG 2 by Monday, December 2.
- Section VI.A from the November 15 report (UDC Back Office Capabilities) was deferred to the December 13 report (identified as Section V.A). The utilities will be expected to address their back office capabilities (data processing, billing, etc.) in terms of their own programs as well as the other programs proposed.

DRAFT
2nd WG2 Report: Marketing/Customer Education, Cost-Effectiveness, Program Evaluation, Pilot Programs
Due December 13, 2002

Report Section/Subsection	Author	Draft Due	Review Due
Executive Summary	?	?	
I. Introduction			
A. Mission for >200 kW Customers	Kaneshiro	12/2	
B. Role of this Report	Kaneshiro	12/2	
II. Fundamental Considerations			
A. Need for Customer Education	C. King/S. Sides	12/2	
B. Role of Marketing	C. King/S. Sides	12/2	
C. Monitoring and Evaluation	LBL(?)/M. Jaske	12/2	
III. Specific Marketing, Customer Education, Monitoring, Evaluation Plans			
A. PG&E Proposal	PG&E	12/2	
(1) General Description - Objectives	"	12/2	
(2) Customer Education Plan	"	12/2	
(3) Marketing Plan	"	12/2	
(4) Range of Customer Participation	"	12/2	
(5) Monitoring and Evaluation Plans	"	12/2	
B. SCE Proposal	SCE	12/2	
C. SDG&E Proposal	SDG&E	12/2	
D. ACWA Recommendations[1]	L. House	12/2	
E. CPA Recommendations[1]	J. Flory	12/2	
IV. Cost Effectiveness Analysis			
A. Description of Framework	S. Anderson	12/2	
B. Assumptions and Inputs	PG&E, SCE, SDG&E	12/2	
C. Results	S. Anderson	12/2	

[1] The specific IOU plans (Sections A-C) will be limited to their own program/tariff proposals. WG 2 decided that ACWA and CPA should provide their recommendations as to how marketing and customer education by the IOUs should be done for their respective proposals as well as recommendations for monitoring and evaluation plans.

V. Generic Implementation Issues			
A. UDC Back Office Capabilities[2]	PG&E, SCE, SDG&E	12/2	
B. Cost Recovery[3]	ORA	12/2	
VI. Pilot Programs			
A. IM-Serv-Invensys Proposal[4]	G. Lizak	12/2	
B. Infotility RTP Proposal[4]	J. Desmond	12/2	
VII. Recommendations[5]	All WG 2	11/26	
APPENDICES			
A. List of Authors	Kaneshiro	12/2	
B. Meeting Minutes	Kaneshiro	12/2	

[2] The IOUs will be responsible for evaluating their data processing/billing capabilities regarding their own proposals as well as all of the proposals.

[3] ORA noted that there are some unresolved differences concerning cost recovery that could require additional write-up for the December 13 report.

[4] No decision has been made as to whether either pilot proposal will be included in the December 13 report. Pilot proponents should use the template circulated by CEC/CPUC staff. These items are noted here as placeholders.

[5] All WG 2 participants are encouraged to send their draft recommendations to M. Jaske by November 26. The draft recommendations will be compiled and re-circulated for discussion at the 12/3 WG2 meeting.

Working Group 2
December 3, 2002 Meeting Minutes

I. Getting Oriented

Several handouts were provided: revised meeting agenda, PIER Project Fact Sheet (CEC), Standard Practice Manual Cost Benefit Tests Distilled for Demand Response (S. Anderson), Issues for Cost Effectiveness Evaluation (C. Silsbee), Two-Part RTP Pilot Proposal (Infotility), Constrained T&D Peak Capacity Proposal (IMServ-Invensys), and several draft sections for the December 13 report.

II. Conducting Cost-Effectiveness Tests for Each Proposal

WG 2 decided to delay discussion of this item until after lunch as some key participants were not present in the morning.

S. Anderson reported that he received inputs from each of the proposal proponents and had run the Standard Practice Manual cost benefit tests, but he expressed reservations about the initial results. Part of his concern is based on the potential effect of existing regulation on the equations used in the tests. Another concern was that the outcomes don't seem to make sense or appear contradictory, which could be due to a 'mismatch' between the SPM and demand response programs. C. Silsbee (SCE) noted that SPM was originally designed for energy efficiency programs, and thus its use, even if modified, may produce misleading results. One fundamental problem noted by Silsbee is that it was unclear as to what specific cost-effectiveness questions needed to be answered.

WG 2 participants decided that given the impending deadline for the report, it would not be possible to take a completely different approach or methodology. WG 2 participants determined that a separate conference call be set up for all interested in participants on Thursday, December 5 to come up with a workable approach for the December 13 report.

III. Monitoring and Evaluation Plan

M. Jaske summarized the write-up for the December 13 report, which emphasized in-depth evaluation of marketing plans, participation patterns, demand response patterns, etc. The write-up also recommends a forum by which all demand response programs can be evaluated and assessed for their effectiveness. There was support for a forum to encompass both dynamic pricing and load curtailment activities in a single forum. IOU participants noted that their current plans for monitoring and evaluation do not quite capture the level of effort prescribed by the Jaske write-up and thus there could likely be budget impacts if the Commission were to fully adopt what Jaske recommends. WG 2 participants also focused on how to best evaluate demand response programs across the board, and also in relation to supply resources such as through a procurement process.

The IOU participants noted that it may make sense to incorporate data from the demand response programs into the monthly interruptible program reports so that the Commission and the parties are kept up-to-date regarding costs and sign-ups.

IV. Pilots for >200 kW Customers

G. Lizak (IMServ-Invensys) presented a pilot for constrained transmission and distribution peak capacity. The pilot will focus on customers located in constrained transmission and distribution (T&D) areas. The general concept is to give customers reduced transmission and distribution charges in return for reducing demand. The proposal was not able to provide specifics on the amount of incentives paid to participants as the data necessary for that remains with the utilities at this time.

WG 2 participants questioned aspects of the pilot pointing out that transmission costs are now regulated by the FERC, and that distribution costs are not necessarily categorized by the utility based on constrained areas. Other WG 2 participants questioned the need for the pilot as it was not clear as to the data it was intending to develop or the questions it was intending to answer. Some WG 2 participants felt that customers in constrained areas can participate in demand response through existing programs such as the Demand Bidding Program if the prices offered in these programs reflected T&D costs.

J. Desmond (Infotility) did a follow-up presentation of a pilot for a two-part RTP tariff (This pilot was initially presented at the November 19 WG 2 meeting). The pilot will allow participants to negotiate baselines with either the IOU or a third party implementer. The pilot is intended to measure customer interest and response to real-time pricing signals, identify customer preferences for baseline methodologies, and identify technical and administrative barriers to implementation, among other things. Estimated budget is $2.5 million for 35 participants, and could be started by June 2003.

IOU participants objected to the pilot in that it represents a deviation from what WG 2 agreed to do in 2003 for two-part RTPs: develop the tariff over the course of several months to be implemented by October 2003. The IOUs also noted that the results of the pilot could not be useful in time for an October implementation, and thus a rollout of the pilot in June necessarily either causes a slip in the RTP schedule, or its results could not be used until after the full-scale RTP is launched. Other WG 2 participants felt that a pilot may be useful as WG 2 begins its effort to design a tariff in 2003, and depending on what the pilot is designed to test, its possible that implementation of the RTP would not be delayed. WG 2 participants agreed that it would be prudent to recommend to WG 1 that there may be need for a pilot to be implemented in 2003, which may or may not cause a delay in the overall development. Participants recognized that describing the possible need for a pilot and requesting some expedited approval process might shorten the time lag between a request for a pilot and receiving authorization for one. WG 2 decided that it was premature to decide if any features of the Infotility proposal would be part of the RTP pilot, and thus it would be best to determine the specifics of the pilot in Phase 2.

V. Recommendations

M. Jaske reported that he did not receive any draft recommendations from any WG 2 participants. WG 2 participants asked if the intent was to revisit the recommendations made in the November 15 report or whether new recommendations should be provided. It was decided that the focus should be on recommendations based on information provided in the December 13 report (Eg. a recommendation concerning a specific customer education or marketing plan).

VI. Review of Status of Draft Report

WG 2 participants reviewed the status of each section for the draft report. The following sections have not yet been circulated: III.D (ACWA's recommendations for marketing, customer education, monitoring and evaluation), IV (Cost Effectiveness Analysis), V.A (PG&E only), V.B (ORA's position on cost recovery), VII (Recommendations). No new appendices were identified, although C. Silsbee's Cost-Effectiveness Issues write-up may become one depending on how Section IV is developed.

WG 2 participants briefly discussed the cost recovery issues, with the IOUs reporting that they have no plans to update or change their proposals as described in the November 15 report. ORA reported that it is having internal discussions concerning the cost recovery mechanisms proposed by the IOUs and was not yet ready to state a position. M. Jaske noted that the WG1 meeting scheduled for December 4 calls for UDCs to present their cost recovery proposals and solicits any other proposals, so that time is short to reconcile views among participants.

D. Hungerford (CEC) notified participants that an integrated draft version of the December 13 report would be circulated late Thursday (Dec. 5). WG 2 participants were encouraged to review the integrated draft and to be prepared to discuss it in detail at the next WG 2 meeting set for Dec. 10. Participants were also encouraged to contact the various authors of the chapters before Dec. 10 if they wanted to suggest text changes for clarification of a section. Authors of any section that was not incorporated into the Dec. 5 draft were encouraged to circulate their write-ups to the group prior to Dec. 10.

VII. Next Steps for Phase II

B. Kaneshiro informed the group that via the ALJ Ruling dated September 5, 2002 WG 1 has asked WG 2 to make recommendations concerning next steps for Phase II. WG 2 participants discussed the idea that the recommendations contained in the November 15 and December 13 reports could be framed as next steps. Participants were instructed to send in their ideas for next steps to M. Jaske before December 10, so that a complete list of steps could be discussed at the next WG 2 meeting.

VIII. Wrap Up and Review

- C. Silsbee (SCE) will set up a conference call with interested participants on Thursday, December 5 to discuss the Cost-Effectiveness analysis, and how to best develop the section for the report.

- An integrated draft version of the December 13 report will be circulated to WG 2 by Thursday, December 5 for review.

- Authors of any section not incorporated into the December 5 circulated draft should circulate their sections to WG 2 before December 10.

- WG 2 participants are encouraged to send suggested text changes to the sections authors if they believe that section can be better clarified.

- The next WG 2 meeting set for December 10 (at the CPUC) will be dedicated to discussing the December 13 report in detail.

- WG 2 participants should send their suggestions for report recommendations and next steps for Phase II to M. Jaske prior to December 10. A composite list will be reviewed and discussed at the meeting.

Working Group 2
December 10, 2002 Meeting Minutes

I. Getting Oriented

Three handouts were provided: meeting agenda, Excerpts of Cost-Effectiveness Draft (S. Anderson), and an updated Section VII (Recommendations and Next Steps) for the December 13 Report (M. Jaske).

II. Reviewing Cost-Effectiveness Tests Results for Each Proposal

S. Anderson reported the initial results of the Standard Practice Manual tests using the inputs provided by the proposal proponents. Anderson also noted that there are notable inconsistencies caused by the combined use of the ratepayer and program administrator tests, the most notable being an apparent double-counting of costs (incentives and program costs) since the equations for both tests include these costs. C. Silsbee (SCE) pointed out that additional adjustments may need to be made to the analysis, as the SPM was not originally designed to assess dynamic pricing tariffs/programs.

WG 2 participants focused on the inputs to the analysis, in particular the expected load reduction forecasts provided by each proponent for their proposal. Some participants voiced concern that the proponents used a variety of methods to calculate their forecasts, which led to inputs not necessarily comparable. Thus, the results are potentially misleading. Participants suggested that the text to the C/E section will need to explain the load forecasts so that it is put into a clearer context. Participants also agreed that the table in Section I.B (Demand Reduction MWh) could use an additional column that shows the percentage of coincident annual peak load for bundled customers above 200 kW. It was also noted that one program was missing from all of the summary tables.

WG 2 also focused on the results of the Participant test noting that even though the test results are positive for nearly all of the programs, it would be misleading to assume that potential participants would be attracted to participate. The reason for that is that the Participant test does not include a value for electricity service to the customer in its equation. In other words, while the test may indicate customer could receive a savings on his bill if he turns off his A/C unit, the customer may not do so because it is 100 degrees outside. The value the customer places on maintaining a level of service under a set of circumstances is not captured in the analysis.

WG 2 also noted a variety of items (text, results) that needed correction or modification. S. Anderson and C. Silsbee agreed to re-write the section taking into consideration all of the input and discussion, and would target close of business Wednesday for the next draft, assuming that proposal proponents could send in their assumptions about load reductions for their proposals.

S. Anderson reported that during the lunch break, interested WG 2 participants discussed further the apparent inconsistency of using both the ratepayer and program administrator tests and decided that given WG2's recommendation for balancing accounts and full cost recovery, it did not make sense to keep the program administrator test as part of the C/E analysis. No one was opposed to that idea.

III. Review of Draft Report

Participants discussed the status of the various sections of the report. Section V.B (Cost Recovery) is currently in flux. The utilities, through SDG&E, circulated a proposed draft for the section, which essentially mirrors the cost recovery section for the WG 3 report. Some participants in WG 2 did not feel comfortable that the proposed section as then written is appropriate for inclusion into the WG 2 report without modifications. Further, participants noted that the section lacks total costs data for each proponent's proposal with some participants noting that such data is necessary to recommend that a cap on program spending should be adopted. WG 2 participants agreed on the following points: 1. the current proposed draft be modified to reflect a WG 2 context, 2. that the direct costs, incentive payments and revenue shortfalls for each proposal, as well as any overarching costs like M&E, be clearly defined in the section, and 3. that recovery of costs for 3rd parties be addressed. Some parties may advocate that these cost estimates be treated as a cap for new demand response activities. ORA agreed to be the point on completing the section by close of business Wednesday.

M. Jaske provided a summation of draft recommendations based on those he had received from participants, as well as suggested Next Steps for Phase 2. WG 2 discussed seven draft recommendations, one of which was dropped (formation of a Monitoring and Evaluation Oversight Committee), and the rest modified both substantially and in minor fashion. WG 2 discussed four proposed Next Steps, one of which dropped (coordinate development of dynamic tariffs with fundamental rate design review), and the rest modified in varying both substantially and in minor fashion. The Next Step receiving the most attention was a proposal to explore locational marginal price and T&D costs as components of demand response tariffs. Several participants believed that this proposal was out-of-scope from the proceeding as well as beyond the jurisdiction of the Commission in at least one respect (transmission rates). Others argued that the WG 2 was directed to explore this issue, and thus the proposal is valid. A compromise was reached by developing language that emphasizes coordination amongst agencies on this issue before launching into the development of a tariff or program.

WG 2 participants identified five other major issues in the draft report:

(1) Did the non-utility proponents incorporate all of the cost data provided by the utilities as part of their input to the cost-effectiveness analysis, in particular the utilities' back-office capability costs? It was determined that additional work needs to be done to ensure that the all of the costs are accounted for properly for each proposal.

(2) The back-office capability descriptions provided by SCE and PG&E did not provide costs/timing information regarding any constraints on implementation of the tariffs/programs that they did not propose. Both utilities agreed to develop this information and provide new drafts for incorporation.

(3) The latest draft for the Monitoring and Evaluation section (II.C) contains recommendations that should either be dropped or moved to the general recommendations made by WG 2. Recommendations #1, #2 and #4 were dropped, and #3 was moved to Section VII (Recommendations).

(4) The Monitoring and Evaluation section (II.C) was also modified to include a provision that programs that were complete failures could be modified or terminated before 2004.

(5) Text changes made to the RTP Pilot section (VI.B).

IV. Review of Next Steps in Proceeding

M. Jaske announced that all section authors must have their final drafts delivered to D. Hungerford by noon, Thursday. M. Jaske also clarified to all participants that given the remaining time, it would not be practical to re-circulate another draft of the report for review and comment. Thus, participants should be preparing their alternative viewpoints for inclusion in the report, and these must be delivered to D. Hungerford by Friday morning. A final draft report is intended to be issued by noon Friday.

Some WG 2 participants announced that rather than sending in alternative viewpoints to be included in the December 13 Report, such viewpoints will be expressed as part of their official comments on both WG 2 reports due December 30, 2002. It was agreed that the Executive Summary of the report should make note of this.

Some WG 2 participants noted that they are not official parties to the proceeding and thus requested that all comments on the reports be circulated to the WG 2 list in addition to the proceeding service list.

V. Conclusion of WG 2 Activities

No specific items were discussed.

APPENDIX C: Two-Part RTP Pilot Proposal - Infotility, Inc.

Background

A Two-Part RTP tariff is one where a customer is billed one rate based on a baseline amount of usage, and is billed (or credited) a second rate for the difference between actual usage and their baseline usage. The two-part tariff is popular among regulatory agencies, and appears to be acceptable in some form to customer groups. As a result of the promising reports of two-part RTP tariffs at the experiential workshops held September 9-10, 2002 in this proceeding, WG2 was encouraged to develop a two-part tariff.[6]

A fundamental problem facing WG 2 is that existing rate designs cannot be readily modified to expose customers to market-based prices. The consensus in WG2 seems to be that there are some hurdles to be overcome before implementation of a two-part tariff is possible, and therefore discussion of two-part RTP should be slightly delayed until after WG2 has finished finalizing their 'quick-win' tariff proposals.

This pilot proposal summarizes a two-part RTP program that can be implemented by June 1, 2003 as a "quick win." It is a voluntary program that maintains the existing rates while employing a "shadow" bill mechanism to expose customers to market-based prices. By leveraging the existing CEC interval meter infrastructure and CEC-funded PIER research efforts, the program overcomes many of the hurdles associated with a two-part tariff. As a result, there is no reason to delay implementation until October 2003. Rather, results of this program operating over the summer could be compared on an equal basis to other dynamic tariff programs in order to provide a basis for evaluation of future tariff designs.

Discussion

In the current draft *<u>Report of Working Group 2 on Dynamic Tariff and Program Proposals</u>*, it is noted that there isn't enough data on customer elasticities that would allow the Group to merge the reliability and economics approaches into a seamless whole. Further, the report indicates that reliability based triggers may not provide the experience needed to understand how customers may respond to market-based pricing triggers.

There is consensus that all dynamic pricing tariffs should be voluntary. Unfortunately, voluntary programs based on class revenue neutral designs create an opportunity for "free riders." If customers made rational economic decisions <u>and</u> did not modify their load consumption patterns, only those customers with load profiles better than the class average would benefit.

It should be noted that while most of the discussion in the Working Group has focused on reliability concerns to avoid energy use during periods of high demand (and by corollary, high prices), there should be equal policy merit for providing customers access to lower cost off-peak energy. This may help to promote sustained behavior changes, including the opportunity to increase load above historic baseline usage during off-peak hours.

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[6] ALJ Ruling of October 2, 2002, pp. 3-4.

Many of the customer concerns expressed about the one-part approach.

In fulfilling this mission, WG 2 was further directed to pursue its best bet for a "quick win" and to develop full-scale tariffs or programs. To that end, the program was designed with the following criteria in mind:

1. Simplicity, - Usage above or below a baseline is charged at the market price.
2. Stability – The CAISO operates an established imbalance market for obtaining real-time price signals.
3. Readily discernable customer risk (recognizing that less risk means less opportunity for bill savings by customers). – As proposed, the TPPRT program allows a customer to quantify the range of risk for a given baseline through the tools developed through PIER research.

Customer Perspective

Real-time pricing and real-time meter data need to be translated into cost so that a customer can make rational decisions based on a value proposition. In order to participate in any RTP programs, customers will need answers to such questions as:

- How can they establish a threshold value for determining when to curtail based on a unique opportunity cost?
- What is the estimated value of a demand reduction (X kW) for a given a set of prices (or price forecast) over a period of time?
- How much will it cost if no action is taken?
- How much reduction is needed to keep costs the same?
- How much savings can be expected given a range of expected prices and a range of demand response?

1. General Description

Infotility's Two-Part RTP proposal for large customers is a voluntary alternative dynamic pricing program that exposes customers to market prices. In anticipation of full rollout, it is designed to mirror the wholesale market procedures for submitting load schedules and settling based on deviations in the real-time imbalance markets. It builds on the CEC Two-Part Tariff previously submitted for consideration to Working Group 2.

The pilot project is designed to:

1. Measure customer interest and response to a real-time price signal across multiple building types.
2. Identify customer preferences for baseline methodologies.
3. Understand specific customer education requirements needed prior to participation under a two-part RTP tariff.
4. Identify technical and administrative barriers to implementation that might be expected under a full-roll out.
5. Measure customer satisfaction associated with participation in a two-part RTP pilot tariff.

6. Present a set of recommendations to the Commission based on lessons learned from operating the pilot project..

Key program elements are:

- All participating customers remain on their existing tariff schedules and are billed based on actual usage under current operating procedures.
- Customers are debited or credited at a second rate (the market price) for the difference between actual usage and their baseline usage
- The difference between actual and baseline is charged (or credited) at the inc and dec CAISO imbalance energy market prices
- Baselines are negotiated
- Baselines may be adjusted monthly
- Baselines may also be adjusted on a day ahead basis (Baselines could be automatically adjusted on a day-ahead basis to account for weather sensitive loads by incorporating a temperature forecast and a load forecast. In addition to minimizing the imbalance schedule, it would also then establish a real-time economic price for which customers would earn credit for reducing load below the baseline. In no case would adjusted baselines be established above historic peak demands.)
- At the end of each month, customers receive a statement summarizing their performance relative to the baseline methodology employed under the program.
- If there is a net positive balance, customers earn an incentive credit.
- If there is a net negative balance, customer is charged a debit.
- At the end of the program, customer is eligible to receive an incentive payment equal to the positive balance at the end of the program. If there is a negative balance, customer receives nothing.

Infrastructure details

- The program utilizes the existing CEC interval data meter infrastructure for calculating performance against the baseline.
- The program utilizes tools developed under CEC PIER Research, including real-time price, cost and meter data feeds, together with customer-defined alerts to provide the customer with detailed information to answer the questions identified under the Customer Perspective Section, referenced above.
- For schedule adjustments on a day-ahead basis, program could utilize the scheduling tool developed by the CPA for the Demand Reserves Partnership program
- Market prices and meter data are published to an Excel spreadsheet template, allowing alternative baseline methodologies to be employed without significant programming cost.
- At any time, customers and utilities can view the current and cumulative credit balance, load information and price information for each participating customer in the program, subject to authorizations.
- Aggregate information on price, meter or performance data would be available
- A statement (a shadow bill) showing debits and credits earned.

Optional

- Establish a market price to use if there is a reliability trigger
- Eliminate the day-ahead adjustments for the program operation to simplify administration
- If real-time market prices remain low over the summer, introduce artificial price volatility in order to observe response to high price signals.

Comments

This TPRTP program is designed as a transition program designed to measure customer response to market price triggers while providing revenue loss protection to the utilities. It can be operated in parallel with existing tariffs.

Under a full-scale rollout, customers would be exposed to both the upside and downside risk associated with their performance against a baseline. Load schedules for participating customers would be submitted under a separate Resource Id to the CAISO consistent with current procedures.

There is minimal downside risk to the customer (no penalty for negative balance). There is minimal risk to the utility (customer pays bill based on actual usage under existing tariff). The program provides real-time feedback to all participants.

Since the program relies upon a shadow bill generated from interval data currently available to the customer, the program could be administered either through a third party or through a utility. This proposal is not intended to address the merits of either approach.

One real issue for two-part tariffs is the low volatility of current market prices. The second part of a two-part tariff will rely on wholesale market prices, which appear to be relatively low and stable at this point in time. There were concerns that these low and stable prices will not incent any demand response. This should not be a concern because if in fact real-time prices remain low, then reliability-based triggers are also unlikely to be used.

Funding Issues

This proposal assumes that some incentive pool is needed to transition customers to two-part tariff. However, it is further noted that the expected incentive level could be established at less than projected cost of free ridership under a class revenue neutral voluntary tariff.

The amount of incentives made available could be bounded in several ways:

- A maximum incentive pool, distributed up to a certain limit. (Customers compete against each other to perform)

- A maximum number of participants or Megawatts

- A maximum incentive per customer

Since the incentives are always net of deviations from baseline, positive performance is offset from poor performance, and could stretch the incentive pool.

2. Targeted Participation

Expected participants would be recruited from those organizations whose members have expressed a direct interest in a two-part tariff in the past. These organizations include, but are not limited to, the Silicon Valley Manufacturing Group (SVMG), OBMC program participants excluded from Demand Response Programs, CMTA, BOMA, BAF and other business and trade associations.

The pilot program would not be applicable for direct access customers.

3. Requirements to Participate

This program would be offered and available to all large bundled service customers (those with at least 200 kW of maximum demand). Nearly all of these customers have already received the interval meters that would be needed to participate, through last year's AB1x29 metering program. (A small number of additional meters might need to be installed for those participants with loads that did not qualify for meters during the AB1x29 implementation period.) Any additional equipment requirements needed for receipt of the real-time price and meter data would be relatively modest, because the many of the tools will have been developed by CEC PIER research.

No new equipment is needed to participate in this program. Participants will be supplied with a free software tool that will provide them with the ability to define business rules based on triggers specific to their usage relative to baseline and/or price signals from the CAISO.

Customer may elect to automate an EMS response to price triggers at a separate cost.

4. Source of Price Signal

Participants would be notified of the applicable price based on a forecast and the ex-post price of the CAISO imbalance energy market for which their load is scheduled.
With a forecast component, participants would be able to plan for and expect that the highest price signals will be applied on the warmest summer weekdays, and might continue for several days during extended heat waves.

As previously mentioned, there is an option to introduce artificial price volatility in the event the real-time market price remains low during the course of the pilot, thus ensuring that participants will be exposed to higher then average prices to measure response to real-time price signals.

5. Intended Level of Participation

As a pilot project, the objective would be to enroll 250MW of connected load under the program. A second objective would be to have up to 35 participants, including representation from a cross selection of building types.

6. Sources/Levels of Costs

The pilot program would incur a certain amount of one-time incremental start-up costs to implement this program, largely for metering, the creation of a shadow bill template in Excel, operation of the servers needed to acquire and publish the real-time price signals during the course of the pilot, connection to a pulse initiator for gathering and reporting real-time energy usage, programming, testing, data retrieval, customer recruitment.

The project would also incur costs associated with the amount of net positive incentives earned under the pilot project based on the usage.

Estimated budget

Per customer hardware/gateway/telemetry: ($3000 * 35 participants)	$100,000
Software modifications to create Excel shadow bill & report templates	$45,000
Program recruitment/marketing/education/workshops	$30,000
Program operation: (June – September), including customer support	$80,000
Data Collection, evaluation and final report	$45,000
<u>Maximum Incentive Pool</u>:	$2,500,000
Total estimated budget (NTE)	$2,800,000

Final estimates for this cost category will be provided in the December 13 report, which will address marketing and customer education considerations.

Since customers will continue to pay actual costs under existing tariffs, there are no revenue shortfall associated with: (1) the "structural" or "self-selection" savings from free ridership, and (2) the "dynamic" bill savings that result when customers do change their loads in response to the new prices.

7. Method of Cost Recovery

Pilot project funded from CPUC public goods charge.

8. Estimated Start Date

Recruitment: April 1, 2003
Pilot start: June 1, 2003
Pilot End: September 30, 2003
Final report: November 15, 2003

9. Method of Implementation

The pilot program could be administered by a third party with or without the administrative support of an Investor-owned utility. Some coordination would be required to minimize potential overlap between IOU tariffs. Much of the coordination required under this pilot would follow the established procedures for customers that have participated in the CAISO's Demand Reserves Program or the CPA's Demand Reserves Partnership Program.

Under the pilot, there is no interface required to a utility's billing system.

Educations materials would need to be be developed that explain the operation of a two-part tariff along with information on how the pilot program operates and what will be expected of customers. Some training in the use of the software tool to monitor performance and create business rules would necessary for each participant.

The real-time energy information tool that customers would use during the pilot has been developed under the CEC PIER program. It is expected that some additional modification to that tool will also have been completed prior to the pilot project start based on feedback from initial users.

Key program elements and infrastructure requirements have been listed under the General Description section above.

10. Monitoring and Evaluation

The use of gateway technology will enable real-time reporting of information for program participants.

An appealing feature of using the CEC real-time information tool for the pilot is that the tool provides both real-time and cumulative performance reporting for each individual participant as well as aggregate reporting capabilities.

Customers and utilities would have access to information relevant to each meter and to each inc and dec price for the appropriate CAISO demand zone. The combination of price and meter data against a customer-specific baseline would also provide an up-to-the-minute running total of incentives earned under the program.

The final report would be designed to capture both the qualitative and quantitative impacts of the pilot project in accordance with the research objectives identified in the General Description section of this report.

11. How Results Will Be Used

Infotility believes that this pilot, as proposed, can provide insight to many of the issues raised in the Working Group 2 regarding a Two Part Tariff:

Some of IOUs expressed concern about the process of developing Customer Baseline Loads (CBLs) for individual customers. Specifically,

1. *The IOUs anticipate CBL development as costly*

The cost to develop a customer baseline can be minimized by applying an agreed upon standard methodology. Alternatively, the use of Excel templates in combination with the PIER research tools allows experimentation of alternative baseline.

2. *Administratively complex*

Using the tools developed under the PIER research program, the 2 Part RTP tariff can be deployed by publishing a real-time price feed to an Excel spreadsheet template. The use of a shadow bill eliminates some of the short term programming changes that would otherwise be needed. Limiting payment until the end of the program minimizes processing costs. The use of a third party could potentially simplify some of the workload.

3. *Potentially litigious (customers complaining about the CBLs a year later when their load shape has changed for different reasons).*

As proposed, all CBLs can be adjusted monthly, and on a day ahead basis.

4. *The IOUs experience with the OBMC program as an example of how difficult a CBL development can be.*

Much of the difficulty was with accounting temperature sensitive loads. As proposed, temperature sensitive loads could be handled by use of a forecasting tool and making adjustments in the Day Ahead market.

5. *Some discussion focused on the whether the two part RTP tariff would be difficult for customers to understand*

Large customers have demonstrated their ability to engage in forward contracts for a variety of other commodities. Provided that there is real-time access to information and reporting, along with timely alerts to allow the customer to modify their load, this should be no more or less challenging than other RTP tariffs

6. *Questions as to whether some customers would need to hire professionals to effectively track information necessary for the tariff to be useful.*

Tools developed under the CEC PIER research would be available to customers. These tools would provide the answers the questions identified under Customer considerations, referenced earlier.

Appendix D: Cost Effective Equations and Inputs

EQUATIONS USED FOR COST EVALUATION

Total Resource Cost Tests Equations

NPVTRC = BTRC - CTRC

BCRTRC = BTRC/CTRC

Where

$$BRTC = \sum_{t=1}^{N} \frac{UAC_t}{(1+d)^{t-1}}$$

$$CRTC = \sum_{t=1}^{N} \frac{PRC_t + PCN_t}{(1+d)^{t-1}}$$

Participant Tests Equations

NPVP = BP - CP

BCRPVP = BP/CP

Where

$$BP = \sum_{t=1}^{N} \frac{BC_t + INC_t}{(1+d)^{t-1}}$$

$$CP = \sum_{t=1}^{N} \frac{PC_t}{(1+d)^{t-1}}$$

Ratepayer Impact Measure Test Equations

NPVRIM = BRIM - CRIM

BCRRIM = BRIM/CRIM

Where

$$BRIM = \sum_{t=1}^{N} \frac{UAC_t}{(1+d)^{t-1}}$$

$$CRIM = \sum_{t=1}^{N} \frac{BC_t + PRC_t + INC_t}{(1+d)^{t-1}}$$

INPUTS

Cost Effectiveness Equation Inputs

Sheet 1 of 7

Proposer	Program	Start Year	Financial Discount Rate	DmdReduc_mWhr
ACWA	**CPP**	2003	0.09	5400
CPA	**CallOp**	2003	0.09	20000
CPA	**NonSpAS**	2003	0.09	10000
CPA	**SupEn**	2003	0.09	1500
IMS	**TransPilot**	2003	0.09	2500
PG&E	**CPP**	2003	0.09	12600
PG&E	**DBP**	2003	0.09	1176
SCE	**DBP**	2003	0.09	2520
SCE	**RTPIndex**	2003	0.09	386.4
SDG&E	**DBP**	2003	0.09	32
SDG&E	**HPO**	2003	0.09	1256.7
ACWA	**CPP**	2003	0.09	5400
CPA	**CallOp**	2003	0.09	20000
CPA	**NonSpAS**	2003	0.09	10000
CPA	**SupEn**	2003	0.09	1500
IMS	**TransPilot**	2003	0.09	2500
PG&E	**CPP**	2003	0.09	12600
PG&E	**DBP**	2003	0.09	1176
SCE	**DBP**	2003	0.09	2520
SCE	**RTPIndex**	2003	0.09	386.4
SDG&E	**DBP**	2003	0.09	32
SDG&E	**HPO**	2003	0.09	1256.7

Cost Effectiveness Equation Inputs

Proposer	Program	BCt1	BCt2	BCt3	BCt4	BCt5	BCt6	BCt7	BCt8	BCt9	BCt10	BCt11
ACWA	**CPP**	$3,855	$3,855	$3,855	$3,855	$3,855	$3,855	$3,855	$3,855	$3,855	$3,855	$3,855
CPA	**CallOp**	$3,600	$3,600	$3,600	$3,600	$3,600	$3,600	$3,600	$3,600	$3,600	$3,600	$3,600
CPA	**NonSpAS**	$1,800	$1,800	$1,800	$1,800	$1,800	$1,800	$1,800	$1,800	$1,800	$1,800	$1,800
CPA	**SupEn**	$270	$270	$270	$270	$270	$270	$270	$270	$270	$270	$270
IMS	**TransPilot**	$450	$450	$450	$450	$450	$450	$450	$450	$450	$450	$450
PG&E	**CPP**	$9,000	$9,000	$9,000	$9,000	$9,000	$9,000	$9,000	$9,000	$9,000	$9,000	$9,000
PG&E	**DBP**	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
SCE	**DBP**	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
SCE	**RTPIndex**	$2,029	$2,029	$2,029	$2,029	$2,029	$2,029	$2,029	$2,029	$2,029	$2,029	$2,029
SDG&E	**DBP**	$3	$3	$3	$3	$3	$3	$3	$3	$3	$3	$3
SDG&E	**HPO**	$426	$426	$426	$426	$426	$426	$426	$426	$426	$426	$426
ACWA	**CPP**	$3,855	$3,855	$3,855	$3,855	$3,855	$3,855	$3,855	$3,855	$3,855	$3,855	$3,855
CPA	**CallOp**	$3,600	$3,600	$3,600	$3,600	$3,600	$3,600	$3,600	$3,600	$3,600	$3,600	$3,600
CPA	**NonSpAS**	$1,800	$1,800	$1,800	$1,800	$1,800	$1,800	$1,800	$1,800	$1,800	$1,800	$1,800
CPA	**SupEn**	$270	$270	$270	$270	$270	$270	$270	$270	$270	$270	$270
IMS	**TransPilot**	$450	$450	$450	$450	$450	$450	$450	$450	$450	$450	$450
PG&E	**CPP**	$9,000	$9,000	$9,000	$9,000	$9,000	$9,000	$9,000	$9,000	$9,000	$9,000	$9,000
PG&E	**DBP**	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
SCE	**DBP**	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
SCE	**RTPIndex**	$2,029	$2,029	$2,029	$2,029	$2,029	$2,029	$2,029	$2,029	$2,029	$2,029	$2,029
SDG&E	**DBP**	$3	$3	$3	$3	$3	$3	$3	$3	$3	$3	$3
SDG&E	**HPO**	$426	$426	$426	$426	$426	$426	$426	$426	$426	$426	$426

Cost Effectiveness Equation Inputs
Sheet 3 of 7

Proposer	Program	INCt1	INCt2	INCt3	INCt4	INCt5	INCt6	INCt7	INCt8	INCt9	INCt10	INCt11
ACWA	**CPP**	$5,150	$5,150	$5,150	$5,150	$5,150	$5,150	$5,150	$5,150	$5,150	$5,150	$5,150
CPA	**CallOp**	$5,600	$5,600	$5,600	$5,600	$5,600	$5,600	$5,600	$5,600	$5,600	$5,600	$5,600
CPA	**NonSpAS**	$4,000	$4,000	$4,000	$4,000	$4,000	$4,000	$4,000	$4,000	$4,000	$4,000	$4,000
CPA	**SupEn**	$6,000	$6,000	$6,000	$6,000	$6,000	$6,000	$6,000	$6,000	$6,000	$6,000	$6,000
IMS	**TransPilot**	$1,500	$1,500	$1,500	$1,500	$1,500	$1,500	$1,500	$1,500	$1,500	$1,500	$1,500
PG&E	**CPP**	$4,000	$4,000	$4,000	$4,000	$4,000	$4,000	$4,000	$4,000	$4,000	$4,000	$4,000
PG&E	**DBP**	$173	$173	$173	$173	$173	$173	$173	$173	$173	$173	$173
SCE	**DBP**	$378	$378	$378	$378	$378	$378	$378	$378	$378	$378	$378
SCE	**RTPIndex**	$597	$597	$597	$597	$597	$597	$597	$597	$597	$597	$597
SDG&E	**DBP**	$8	$8	$8	$8	$8	$8	$8	$8	$8	$8	$8
SDG&E	**HPO**	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
ACWA	**CPP**	$5,150	$5,150	$5,150	$5,150	$5,150	$5,150	$5,150	$5,150	$5,150	$5,150	$5,150
CPA	**CallOp**	$5,600	$5,600	$5,600	$5,600	$5,600	$5,600	$5,600	$5,600	$5,600	$5,600	$5,600
CPA	**NonSpAS**	$4,000	$4,000	$4,000	$4,000	$4,000	$4,000	$4,000	$4,000	$4,000	$4,000	$4,000
CPA	**SupEn**	$6,000	$6,000	$6,000	$6,000	$6,000	$6,000	$6,000	$6,000	$6,000	$6,000	$6,000
IMS	**TransPilot**	$1,500	$1,500	$1,500	$1,500	$1,500	$1,500	$1,500	$1,500	$1,500	$1,500	$1,500
PG&E	**CPP**	$4,000	$4,000	$4,000	$4,000	$4,000	$4,000	$4,000	$4,000	$4,000	$4,000	$4,000
PG&E	**DBP**	$173	$173	$173	$173	$173	$173	$173	$173	$173	$173	$173
SCE	**DBP**	$378	$378	$378	$378	$378	$378	$378	$378	$378	$378	$378
SCE	**RTPIndex**	$597	$597	$597	$597	$597	$597	$597	$597	$597	$597	$597
SDG&E	**DBP**	$8	$8	$8	$8	$8	$8	$8	$8	$8	$8	$8
SDG&E	**HPO**	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

Cost Effectiveness Equation Inputs
Sheet 4 of 7

Proposer	Program	PCt1	PCt2	PCt3	PCt4	PCt5	PCt6	PCt7	PCt8	PCt9	PCt10	PCt11
ACWA	**CPP**	$15,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
CPA	**CallOp**	$12,000	$2,000	$2,000	$2,000	$2,000	$2,000	$2,000	$2,000	$2,000	$2,000	$2,000
CPA	**NonSpAS**	$7,000	$1,000	$1,000	$1,000	$1,000	$1,000	$1,000	$1,000	$1,000	$1,000	$1,000
CPA	**SupEn**	$9,000	$1,500	$1,500	$1,500	$1,500	$1,500	$1,500	$1,500	$1,500	$1,500	$1,500
IMS	**TransPilot**	$3,000	$500	$500	$500	$500	$500	$500	$500	$500	$500	$500
PG&E	**CPP**	$15,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
PG&E	**DBP**	$1,370	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
SCE	**DBP**	$3,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
SCE	**RTPIndex**	$460	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
SDG&E	**DBP**	$3	$3	$3	$3	$3	$3	$3	$3	$3	$3	$3
SDG&E	**HPO**	$271	$271	$271	$271	$271	$271	$271	$271	$271	$271	$271
ACWA	**CPP**	$15,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
CPA	**CallOp**	$12,000	$2,000	$2,000	$2,000	$2,000	$2,000	$2,000	$2,000	$2,000	$2,000	$2,000
CPA	**NonSpAS**	$7,000	$1,000	$1,000	$1,000	$1,000	$1,000	$1,000	$1,000	$1,000	$1,000	$1,000
CPA	**SupEn**	$9,000	$1,500	$1,500	$1,500	$1,500	$1,500	$1,500	$1,500	$1,500	$1,500	$1,500
IMS	**TransPilot**	$3,000	$500	$500	$500	$500	$500	$500	$500	$500	$500	$500
PG&E	**CPP**	$15,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
PG&E	**DBP**	$1,370	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
SCE	**DBP**	$3,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
SCE	**RTPIndex**	$460	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
SDG&E	**DBP**	$3	$3	$3	$3	$3	$3	$3	$3	$3	$3	$3
SDG&E	**HPO**	$271	$271	$271	$271	$271	$271	$271	$271	$271	$271	$271

Cost Effectiveness Equation Inputs

Sheet 5 of 7

Proposer	Program	PRCt1	PRCt2	PRCt3	PRCt4	PRCt5	PRCt6	PRCt7	PRCt8	PRCt9	PRCt10	PRCt11
ACWA	**CPP**	$1,000	$400	$400	$400	$400	$400	$400	$400	$400	$400	$400
CPA	**CallOp**	$6,200	$4,200	$4,200	$4,200	$4,200	$4,200	$4,200	$4,200	$4,200	$4,200	$4,200
CPA	**NonSpAS**	$5,900	$2,400	$2,400	$2,400	$2,400	$2,400	$2,400	$2,400	$2,400	$2,400	$2,400
CPA	**SupEn**	$4,500	$3,000	$3,000	$3,000	$3,000	$3,000	$3,000	$3,000	$3,000	$3,000	$3,000
IMS	**TransPilot**	$2,000	$1,500	$1,500	$1,500	$1,500	$1,500	$1,500	$1,500	$1,500	$1,500	$1,500
PG&E	**CPP**	$1,000	$400	$400	$400	$400	$400	$400	$400	$400	$400	$400
PG&E	**DBP**	$274	$110	$110	$110	$110	$110	$110	$110	$110	$110	$110
SCE	**DBP**	$274	$110	$110	$110	$110	$110	$110	$110	$110	$110	$110
SCE	**RTPIndex**	$449	$122	$122	$122	$122	$122	$122	$122	$122	$122	$122
SDG&E	**DBP**	$15	$8	$8	$8	$8	$8	$8	$8	$8	$8	$8
SDG&E	**HPO**	$290	$50	$50	$50	$50	$50	$50	$50	$50	$50	$50
ACWA	**CPP**	$1,000	$400	$400	$400	$400	$400	$400	$400	$400	$400	$400
CPA	**CallOp**	$6,200	$4,200	$4,200	$4,200	$4,200	$4,200	$4,200	$4,200	$4,200	$4,200	$4,200
CPA	**NonSpAS**	$5,900	$2,400	$2,400	$2,400	$2,400	$2,400	$2,400	$2,400	$2,400	$2,400	$2,400
CPA	**SupEn**	$4,500	$3,000	$3,000	$3,000	$3,000	$3,000	$3,000	$3,000	$3,000	$3,000	$3,000
IMS	**TransPilot**	$2,000	$1,500	$1,500	$1,500	$1,500	$1,500	$1,500	$1,500	$1,500	$1,500	$1,500
PG&E	**CPP**	$1,000	$400	$400	$400	$400	$400	$400	$400	$400	$400	$400
PG&E	**DBP**	$274	$110	$110	$110	$110	$110	$110	$110	$110	$110	$110
SCE	**DBP**	$274	$110	$110	$110	$110	$110	$110	$110	$110	$110	$110
SCE	**RTPIndex**	$449	$122	$122	$122	$122	$122	$122	$122	$122	$122	$122
SDG&E	**DBP**	$15	$8	$8	$8	$8	$8	$8	$8	$8	$8	$8
SDG&E	**HPO**	$290	$50	$50	$50	$50	$50	$50	$50	$50	$50	$50

Cost Effectiveness Equation Inputs

Proposer	Program	PCNt1	PCNt2	PCNt3	PCNt4	PCNt5	PCNt6	PCNt7	PCNt8	PCNt9	PCNt10	PCNt11
ACWA	CPP	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
CPA	CallOp	$12,000	$2,000	$2,000	$2,000	$2,000	$2,000	$2,000	$2,000	$2,000	$2,000	$2,000
CPA	NonSpAS	$7,000	$1,000	$1,000	$1,000	$1,000	$1,000	$1,000	$1,000	$1,000	$1,000	$1,000
CPA	SupEn	$9,000	$1,500	$1,500	$1,500	$1,500	$1,500	$1,500	$1,500	$1,500	$1,500	$1,500
IMS	TransPilot	$3,000	$500	$500	$500	$500	$500	$500	$500	$500	$500	$500
PG&E	CPP	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
PG&E	DBP	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
SCE	DBP	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
SCE	RTPIndex	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
SDG&E	DBP	$0										
SDG&E	HPO	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
ACWA	CPP	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
CPA	CallOp	$12,000	$2,000	$2,000	$2,000	$2,000	$2,000	$2,000	$2,000	$2,000	$2,000	$2,000
CPA	NonSpAS	$7,000	$1,000	$1,000	$1,000	$1,000	$1,000	$1,000	$1,000	$1,000	$1,000	$1,000
CPA	SupEn	$9,000	$1,500	$1,500	$1,500	$1,500	$1,500	$1,500	$1,500	$1,500	$1,500	$1,500
IMS	TransPilot	$3,000	$500	$500	$500	$500	$500	$500	$500	$500	$500	$500
PG&E	CPP	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
PG&E	DBP	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
SCE	DBP	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
SCE	RTPIndex	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
SDG&E	DBP	$0										
SDG&E	HPO	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

Cost Effectiveness Equation Inputs

Sheet 7 of 7

Proposer	Program	UACt1	UACT2	UACt3	UACt4	UACt5	UACt6	UACt7	UACt8	UACt9	UACt10	UACt11
ACWA	**CPP**	$12,939	$12,939	$12,939	$12,939	$12,939	$12,939	$12,939	$12,939	$12,939	$12,939	$12,939
CPA	**CallOp**	$17,700	$17,700	$17,700	$17,700	$17,700	$17,700	$17,700	$17,700	$17,700	$17,700	$17,700
CPA	**NonSpAS**	$10,850	$10,850	$10,850	$10,850	$10,850	$10,850	$10,850	$10,850	$10,850	$10,850	$10,850
CPA	**SupEn**	$12,803	$12,803	$12,803	$12,803	$12,803	$12,803	$12,803	$12,803	$12,803	$12,803	$12,803
IMS	**TransPilot**	$5,088	$5,088	$5,088	$5,088	$5,088	$5,088	$5,088	$5,088	$5,088	$5,088	$5,088
PG&E	**CPP**	$13,191	$13,191	$13,191	$13,191	$13,191	$13,191	$13,191	$13,191	$13,191	$13,191	$13,191
PG&E	**DBP**	$1,205	$1,205	$1,205	$1,205	$1,205	$1,205	$1,205	$1,205	$1,205	$1,205	$1,205
SCE	**DBP**	$2,638	$2,638	$2,638	$2,638	$2,638	$2,638	$2,638	$2,638	$2,638	$2,638	$2,638
SCE	**RTPIndex**	$407	$407	$407	$407	$407	$407	$407	$407	$407	$407	$407
SDG&E	**DBP**	$680	$680	$680	$680	$680	$680	$680	$680	$680	$680	$680
SDG&E	**HPO**	$398	$398	$398	$398	$398	$398	$398	$398	$398	$398	$398
ACWA	**CPP**	$1,878	$1,878	$1,878	$1,878	$1,878	$1,878	$1,878	$1,878	$1,878	$1,878	$1,878
CPA	**CallOp**	$3,400	$3,400	$3,400	$3,400	$3,400	$3,400	$3,400	$3,400	$3,400	$3,400	$3,400
CPA	**NonSpAS**	$3,700	$3,700	$3,700	$3,700	$3,700	$3,700	$3,700	$3,700	$3,700	$3,700	$3,700
CPA	**SupEn**	$1,605	$1,605	$1,605	$1,605	$1,605	$1,605	$1,605	$1,605	$1,605	$1,605	$1,605
IMS	**TransPilot**	$1,425	$1,425	$1,425	$1,425	$1,425	$1,425	$1,425	$1,425	$1,425	$1,425	$1,425
PG&E	**CPP**	$2,382	$2,382	$2,382	$2,382	$2,382	$2,382	$2,382	$2,382	$2,382	$2,382	$2,382
PG&E	**DBP**	$218	$218	$218	$218	$218	$218	$218	$218	$218	$218	$218
SCE	**DBP**	$476	$476	$476	$476	$476	$476	$476	$476	$476	$476	$476
SCE	**RTPIndex**	$407	$407	$407	$407	$407	$407	$407	$407	$407	$407	$407
SDG&E	**DBP**	$80	$80	$80	$80	$80	$80	$80	$80	$80	$80	$80
SDG&E	**HPO**	$47	$47	$47	$47	$47	$47	$47	$47	$47	$47	$47

Appendix E: SCE Customer Profile Analysis

RTP Customer Profile

Southern California Edison

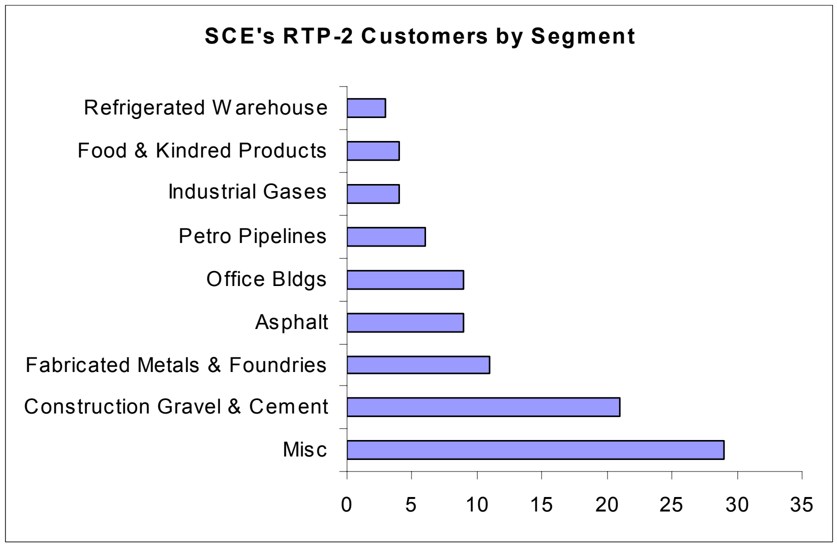
12/20/02 1

RTP Customer Profile

- Target Market
  - Customers able to shift electrical load on short notice
  - Customers with the flexibility to avoid using electricity during high costs periods
  - Customers with low load-factor (able to avoid paying the time-related demand charge incurred under Schedule TOU-8)
- Typical Customer Able to Benefit From RTP
  - Sand and gravel
  - Asphalt
  - Basic Minerals
  - Metals(foundries, fabrication)

SCE's Current RTP Customers

Construction Gravel & Cement	21
Fabricated Metals (foundries)	11
Office Buildings	9
Asphalt	9
Petroleum Pipelines	6
Industrials Gases	4
Food & Kindred Products	4
All other Industrial	4
Air Courier	4
Refrigerated Warehouses	3
Misc Retail	3
Glass	3
Cargo Handling	3
Warehouses	2
Electrical (Batteries)	2
Aircraft/Aerospace	2
Water Supply	1
Schools	1
Printing	1
Petroleum Refining	1
Chemicals	1


SCE's RTP-2 Customers by Segment
Refrigerated Warehouse
Food & Kindred Products
Industrial Gases
Petro Pipelines
Office Bldgs
Asphalt
Fabricated Metals & Foundries
Construction Gravel & Cement
Misc
0
5
10
15
20
25
30
35

12/10/02

4

Bill Comparisons of RTP to TOU-8

- By Customer Type
  - Office Building
  - Class Average
  - Cement
  - Hospital
- Assumptions
  - Load profiles are actual TOU-8 customers
  - CY 2001 actual billing data and temperatures
  - Simulated Temperature scenario is based on a random distribution of temperatures over CY 2001 at the historical frequency of occurrence
  - No change in customer behavior; load reductions or shifts would result in greater savings (or less losses)
  - Charges include energy and time-related demand charges & excludes ratcheted facilities charges

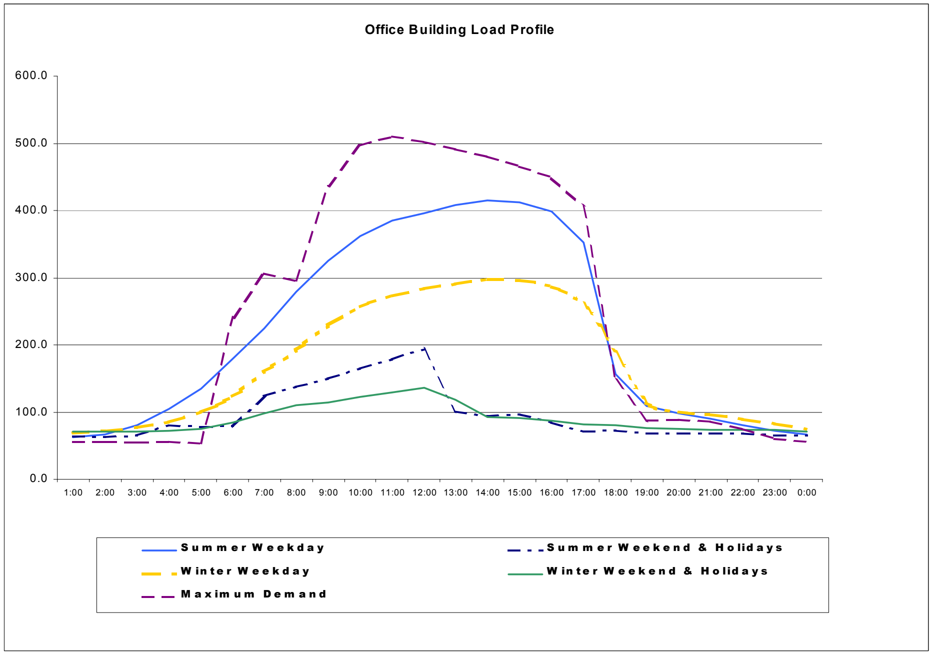
Summary of RTP vs. TOU-8 Bill Comparisons (2001 – No Extreme Days)

Customer Segment	Annual Savings/(Costs)	Annual Average TOU-8 Rate Cents/kWh	Annual Average RTP Rate Cents/kWh
Office Building	22.7 %	17.54	13.55
Cement Company	29.1 %	19.36	13.73
Hospital	25.0 %	12.75	9.57
Large Power Class Average	24.1 %	13.83	10.50

Summary of RTP vs. TOU-8 Bill Comparisons (2001 – Simulated Temperatures)

Customer Segment	Annual Savings/(Costs)	Annual Average TOU-8 Rate Cents/kWh	Annual Average RTP Rate Cents/kWh
Office Building	1.11 %	17.54	17.34
Cement Company	16.64 %	19.36	16.14
Hospital	8.93 %	12.75	11.61
Large Power Class Average	5.80 %	13.83	13.03

12/10/02 7



Office Building Load Profile
600.0
500.0
400.0
300.0
200.0
100.0
0.0
1:00 2:00 3:00 4:00 5:00 6:00 7:00 8:00 9:00 10:00 11:00 12:00 13:00 14:00 15:00 16:00 17:00 18:00 19:00 20:00 21:00 22:00 23:00 0:00
Summer Weekday
Summer Weekend & Holidays
Winter Weekday
Winter Weekend & Holidays
Maximum Demand

12/10/02

8

OFFICE BUILDING LOAD PROFILE

SCE Acct

TOU-8 vs. RTP-2

Rate Analysis

Billing Summary

Scenario Name	Results Amount	Cents /kWh	Dollar Savings	Percent Savings
TOU-8 Firm Service	$243,583	17.54		
RTP-2 Firm Service	$188,213	13.55	$55,370	22.73%

Read Date	TOU-8 Firm Service	RTP-2 Firm Service
Jan-01	14,155.00	10,909.68
Feb-01	13,803.92	10,701.40
Mar-01	15,984.33	12,358.48
Apr-01	14,749.60	11,783.18
May-01	17,292.63	13,331.80
Jun-01	29,961.33	20,807.06
Jul-01	30,038.10	18,957.75
Aug-01	33,334.43	29,048.39
Sep-01	29,702.92	22,939.37
Oct-01	19,365.89	17,852.54
Nov-01	12,939.01	10,033.66
Dec-01	12,255.83	9,489.48
Total $$$'s	$243,582.99	$188,212.78

12/10/02

SIMULATED TEMPERATURE SCENARIO
OFFICE BUILDING LOAD PROFILE

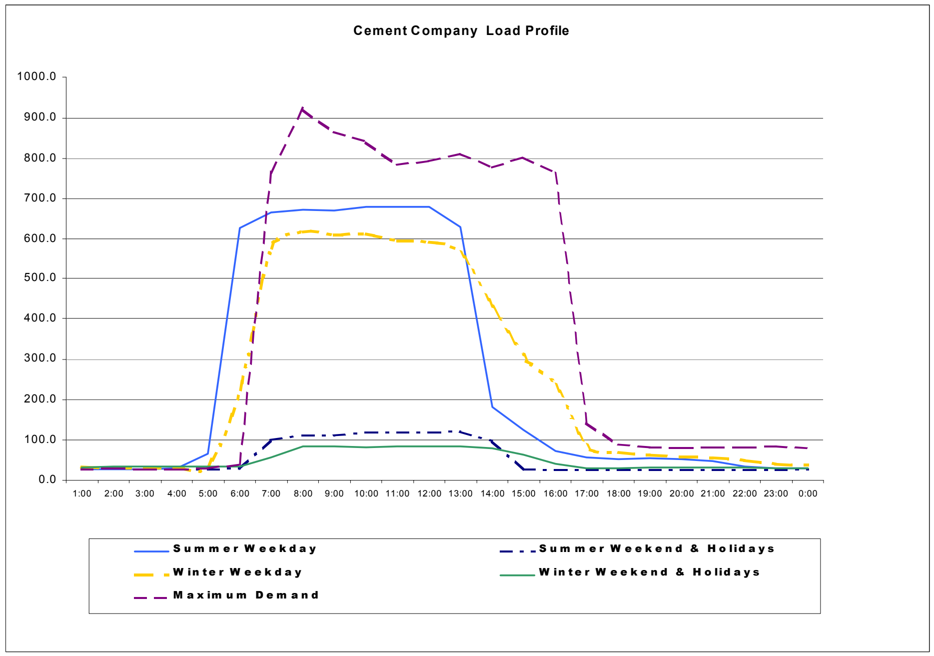
TOU-8 vs. RTP-2

Rate Analysis

Billing Summary

Scenario Name	Results Amount	Cents /kWh	Dollar Savings	Percent Savings
TOU-8 Firm Service	$243,583	17.54		
RTP-2 Firm Service	$240,871	17.34	$2,712	1.11%

Read Date	TOU-8 Firm Service	RTP-2 Firm Service
Jan-01	14,155.00	11,012.34
Feb-01	13,803.92	10,984.64
Mar-01	15,984.33	12,485.69
Apr-01	14,749.60	11,523.36
May-01	17,292.63	13,396.70
Jun-01	29,961.33	41,378.60
Jul-01	30,038.10	45,879.98
Aug-01	33,334.43	30,792.65
Sep-01	29,702.92	30,167.23
Oct-01	19,365.89	13,149.34
Nov-01	12,939.01	10,310.59
Dec-01	12,255.83	9,789.68
Total $$$'s	$243,582.99	$240,870.80


Cement Company Load Profile
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900.0
800.0
700.0
600.0
500.0
400.0
300.0
200.0
100.0
0.0
1:00 2:00 3:00 4:00 5:00 6:00 7:00 8:00 9:00 10:00 11:00 12:00 13:00 14:00 15:00 16:00 17:00 18:00 19:00 20:00 21:00 22:00 23:00 0:00
Summer Weekday
Summer Weekend & Holidays
Winter Weekday
Winter Weekend & Holidays
Maximum Demand

12/10/02

11

CEMENT COMPANY LOAD PROFILE

SCE Acct

TOU-8 vs. RTP-2

Rate Analysis

Billing Summary

Scenario Name	Results Amount	Cents /kWh	Dollar Savings	Percent Savings
TOU-8 Firm Service	$324,471	19.36		
RTP-2 Firm Service	$230,013	13.73	$94,458	29.11%

Read Date	TOU-8 Firm Service	RTP-2 Firm Service
Jan-01	20,926.17	16,745.33
Feb-01	16,616.39	13,556.05
Mar-01	20,443.12	16,236.78
Apr-01	20,057.93	16,088.79
May-01	16,203.31	13,136.15
Jun-01	37,458.84	21,385.70
Jul-01	37,430.14	19,891.06
Aug-01	38,947.88	24,335.45
Sep-01	37,739.96	25,705.78
Oct-01	28,525.39	23,264.85
Nov-01	25,248.48	20,011.99
Dec-01	24,873.04	19,655.13
Total $$$'s	$324,470.64	$230,013.07

SIMULATED TEMPERATURE SCENARIO
CEMENT COMPANY LOAD PROFILE

TOU-8 vs. RTP-2

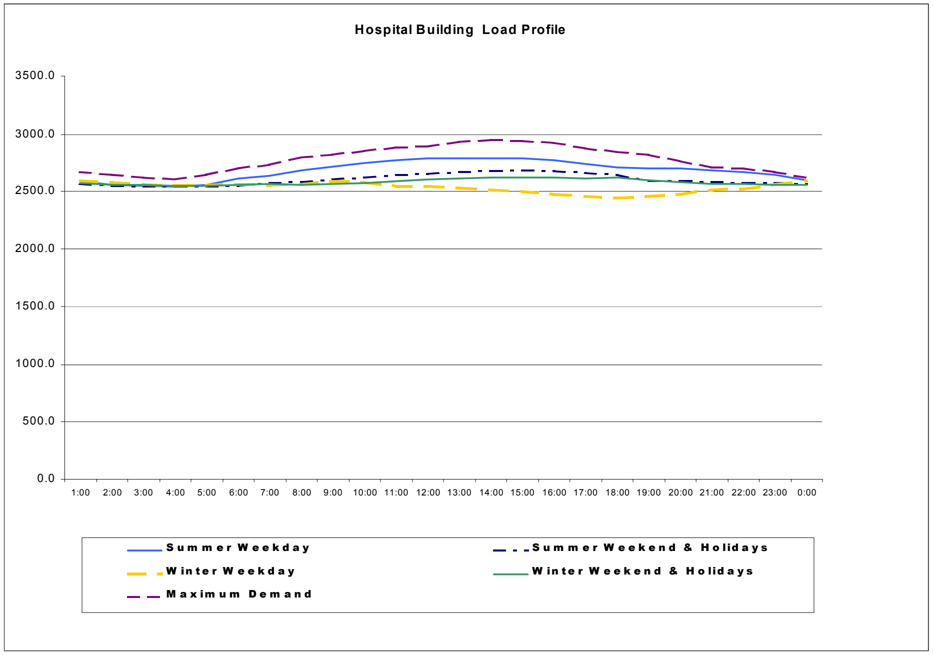
Rate Analysis

Billing Summary

Scenario Name	Results Amount	Cents /kWh	Dollar Savings	Percent Savings
TOU-8 Firm Service	$324,471	19.36		
RTP-2 Firm Service	$270,485	16.14	$53,985	16.64%

Read Date	TOU-8 Firm Service	RTP-2 Firm Service
Jan-01	20,926.17	16,832.56
Feb-01	16,616.39	13,892.69
Mar-01	20,443.12	16,284.91
Apr-01	20,057.93	15,940.19
May-01	16,203.31	13,155.01
Jun-01	37,458.84	37,882.45
Jul-01	37,430.14	40,695.47
Aug-01	38,947.88	27,394.10
Sep-01	37,739.96	28,014.92
Oct-01	28,525.39	19,897.09
Nov-01	25,248.48	20,220.85
Dec-01	24,873.04	20,275.20
Total $$$'s	$324,470.64	$270,485.45

12/10/02 13



Hospital Building Load Profile
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3000.0
2500.0
2000.0
1500.0
1000.0
500.0
0.0
1:00 2:00 3:00 4:00 5:00 6:00 7:00 8:00 9:00 10:00 11:00 12:00 13:00 14:00 15:00 16:00 17:00 18:00 19:00 20:00 21:00 22:00 23:00 0:00
Summer Weekday
Summer Weekend & Holidays
Winter Weekday
Winter Weekend & Holidays
Maximum Demand

12/10/02

14

HOSPITAL LOAD PROFILE

SCE Acct

TOU-8 vs. RTP-2

Rate Analysis

Billing Summary

Scenario Name	Results Amount	Cents /kWh	Dollar Savings	Percent Savings
TOU-8 Firm Service	$2,892,915	12.75		
RTP-2 Firm Service	$2,170,864	9.57	$722,051	24.96%

Read Date	TOU-8 Firm Service	RTP-2 Firm Service
Jan-01	197,289.63	147,049.64
Feb-01	188,821.41	141,757.81
Mar-01	211,948.71	157,648.81
Apr-01	216,824.11	163,592.19
May-01	216,044.68	161,283.74
Jun-01	297,171.06	210,931.62
Jul-01	302,011.18	191,383.90
Aug-01	311,134.78	259,063.45
Sep-01	291,801.20	228,018.40
Oct-01	235,175.55	193,879.54
Nov-01	208,644.28	155,052.21
Dec-01	216,048.50	161,203.04
Total $$$'s	$2,892,915.08	$2,170,864.34

12/10/02 15

SIMULATED TEMPERATURE SCENARIO
HOSPITAL LOAD PROFILE

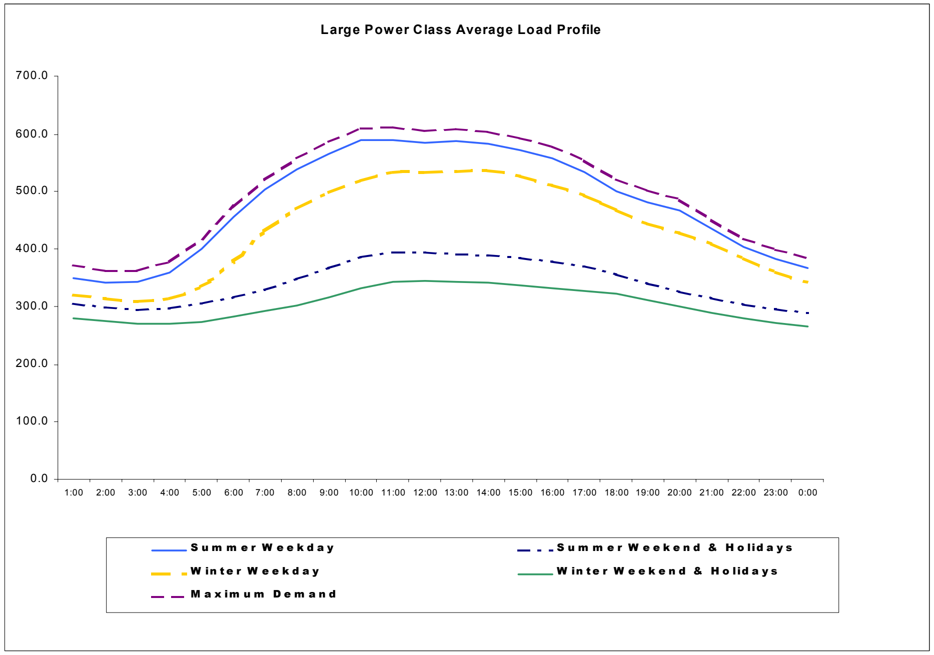
TOU-8 vs. RTP-2

Rate Analysis

Billing Summary

Scenario Name	Results Amount	Cents /kWh	Dollar Savings	Percent Savings
TOU-8 Firm Service	$2,892,915	12.75		
RTP-2 Firm Service	$2,634,616	11.61	$258,299	8.93%

Read Date	TOU-8 Firm Service	RTP-2 Firm Service
Jan-01	197,289.63	149,860.34
Feb-01	188,821.41	146,011.79
Mar-01	211,948.71	160,833.55
Apr-01	216,824.11	163,052.37
May-01	216,044.68	163,419.79
Jun-01	297,171.06	375,369.93
Jul-01	302,011.18	415,911.89
Aug-01	311,134.78	280,325.78
Sep-01	291,801.20	289,193.78
Oct-01	235,175.55	164,634.44
Nov-01	208,644.28	159,876.40
Dec-01	216,048.50	166,126.12
Total $$$'s	**$2,892,915.08**	**$2,634,616.18**


Large Power Class Average Load Profile
700.0
600.0
500.0
400.0
300.0
200.0
100.0
0.0
1:00 2:00 3:00 4:00 5:00 6:00 7:00 8:00 9:00 10:00 11:00 12:00 13:00 14:00 15:00 16:00 17:00 18:00 19:00 20:00 21:00 22:00 23:00 0:00
Summer Weekday
Summer Weekend & Holidays
Winter Weekday
Winter Weekend & Holidays
Maximum Demand

12/10/02

17

LARGE POWER CLASS AVERAGE

SCE Acct

TOU-8 vs. RTP-2

Rate Analysis

Billing Summary

Scenario Name	Results Amount	Cents /kWh	Dollar Savings	Percent Savings
TOU-8 Firm Service	$494,694	13.83		
RTP-2 Firm Service	$375,579	10.50	$119,115	24.08%

Read Date	TOU-8 Firm Service	RTP-2 Firm Service
Jan-01	33,285.31	24,913.80
Feb-01	30,768.27	23,222.29
Mar-01	34,910.26	26,133.78
Apr-01	34,135.41	26,048.58
May-01	36,963.86	27,761.79
Jun-01	51,678.41	36,512.64
Jul-01	54,325.84	35,900.66
Aug-01	57,861.69	48,941.47
Sep-01	53,474.15	41,903.83
Oct-01	41,182.33	34,543.73
Nov-01	33,949.67	25,492.18
Dec-01	32,159.15	24,204.14
Total $$$'s	$494,694.34	$375,578.91

SIMULATED TEMPERATURE SCENARIO
LARGE POWER CLASS AVERAGE

TOU-8 vs. RTP-2

Rate Analysis

Billing Summary

Scenario Name	Results Amount	Cents /kWh	Dollar Savings	Percent Savings
TOU-8 Firm Service	$494,694	13.83		
RTP-2 Firm Service	$465,997	13.03	$28,697	5.80%

Read Date	TOU-8 Firm Service	RTP-2 Firm Service
Jan-01	33,285.31	25,236.64
Feb-01	30,768.27	23,903.49
Mar-01	34,910.26	26,519.73
Apr-01	34,135.41	25,843.00
May-01	36,963.86	28,033.71
Jun-01	51,678.41	67,767.94
Jul-01	54,325.84	80,613.67
Aug-01	57,861.69	53,417.35
Sep-01	53,474.15	54,810.98
Oct-01	41,182.33	28,631.23
Nov-01	33,949.67	26,289.73
Dec-01	32,159.15	24,929.48
Total $$$'s	$494,694.34	$465,996.95

12/10/02 19

SDG&E's
Hourly Pricing Option

Illustrative Bill Impacts

Presented for

Working Group Two

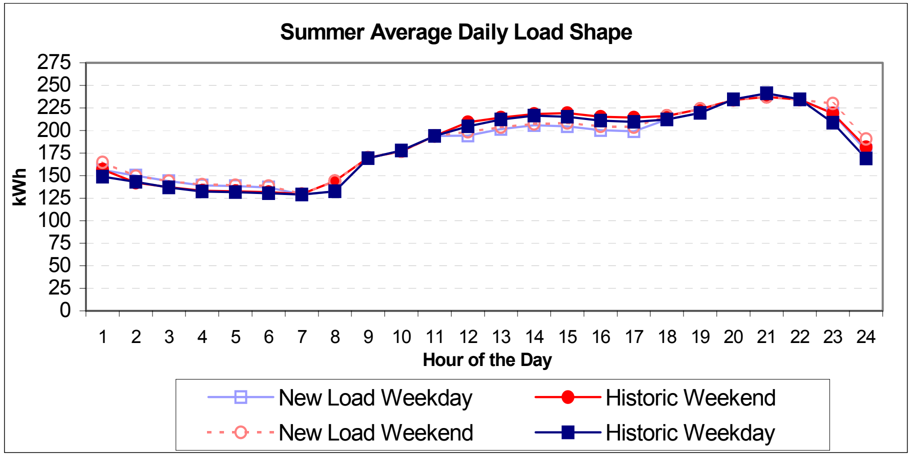
Advanced Metering & Dynamic Pricing OIR

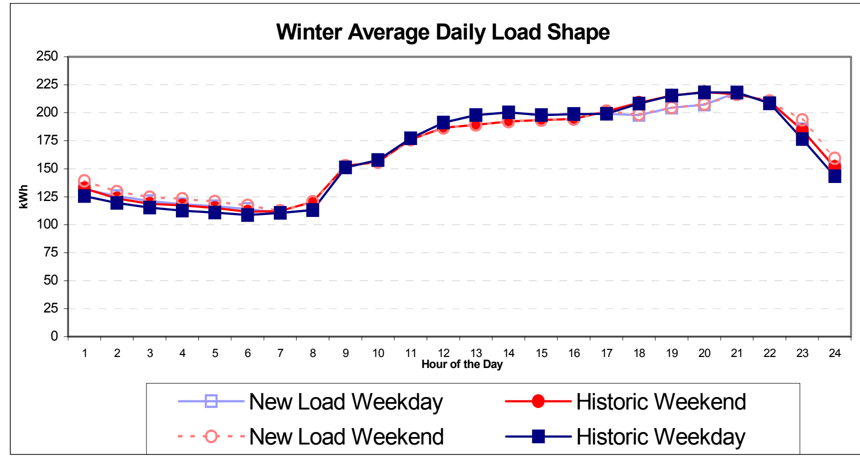
October 23, 2002

SDG&E's Hourly Pricing Option

- Bill Impact Illustrations
  - HPO prices based on historical price index, and load data
    - Price "backcast" is not a price forecast
  - Monthly electric energy commodity cost only
  - T & D costs not considered
  - Six actual customers
    - Illustrates a range of possible impacts
    - Can not be generalized as typical or average customers
  - Includes load shift assumptions in "New Load":
    - 5% On-peak reduction
    - 5% Off-peak increase
    - May not be representative of actual customer response

Customer: Grocery Store



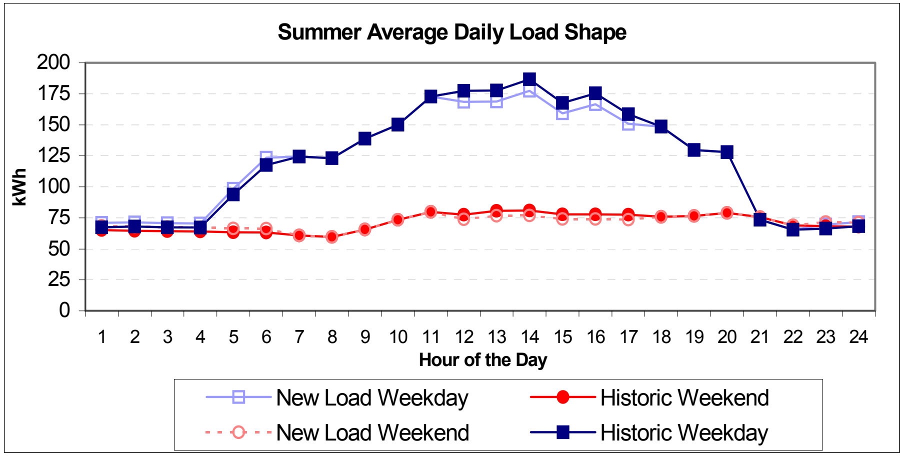


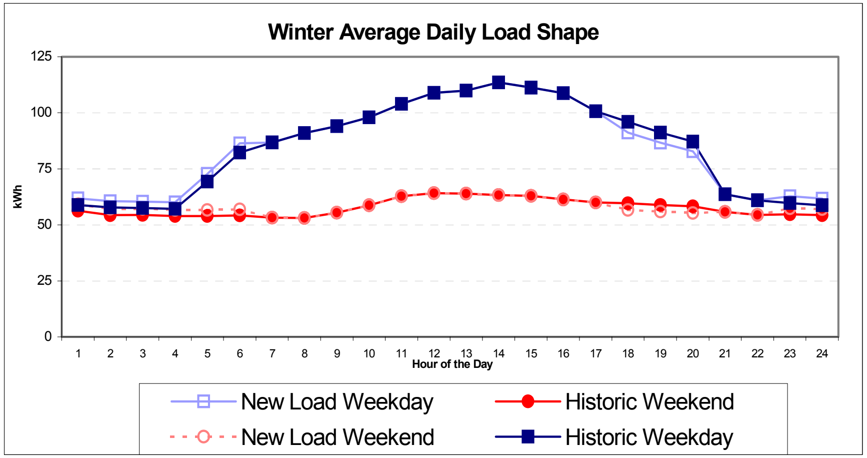
Electric Energy Commodity Cost Comparison (Excludes T&D rate impacts)

New Load assumes 5% decrease in on-peak consumption & 5% increase in off-peak consumption.

			Data					
Year	Month	Season	Hist. Load w/ EECC Px	Hist. Load w/ HPO Px	New Load w/ EECC Px	New Load w/ HPO Px	**Benefit of HPO**	**Benefit of HPO & New Load**
2001	1	Winter	$0	$0	$0	$0	$0	$0
	2	Winter	$0	$0	$0	$0	$0	$0
	3	Winter	$0	$0	$0	$0	$0	$0
	4	Winter	$0	$0	$0	$0	$0	$0
	5	Summer	$0	$0	$0	$0	$0	$0
	6	Summer	$0	$0	$0	$0	$0	$0
	7	Summer	$0	$0	$0	$0	$0	$0
	8	Summer	$10,200	$10,102	$10,168	$10,018	$98	$182
	9	Summer	$10,670	$10,661	$10,631	$10,601	$9	$69
	10	Winter	$10,472	$10,439	$10,510	$10,441	$33	$32
	11	Winter	$10,040	$10,091	$10,070	$10,083	-$51	-$42
	12	Winter	$8,177	$8,277	$8,194	$8,263	-$100	-$87
2002	1	Winter	$0	$0	$0	$0	$0	$0
	2	Winter	$0	$0	$0	$0	$0	$0
	3	Winter	$0	$0	$0	$0	$0	$0
	4	Winter	$0	$0	$0	$0	$0	$0
	5	Summer	$0	$0	$0	$0	$0	$0
	6	Summer	$0	$0	$0	$0	$0	$0
	7	Summer	$0	$0	$0	$0	$0	$0
	8	Summer	$0	$0	$0	$0	$0	$0
	9	Summer	$0	$0	$0	$0	$0	$0
Grand Total			$49,559	$49,570	$49,573	$49,406	-$11	$153

Customer: Office Building



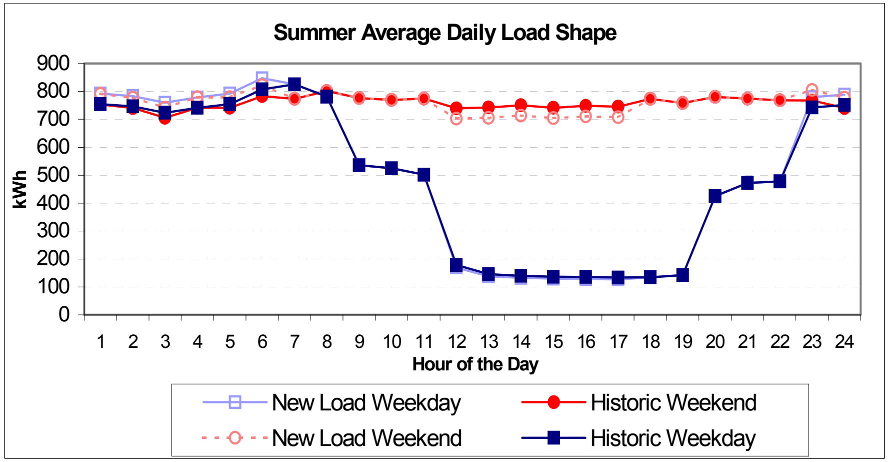


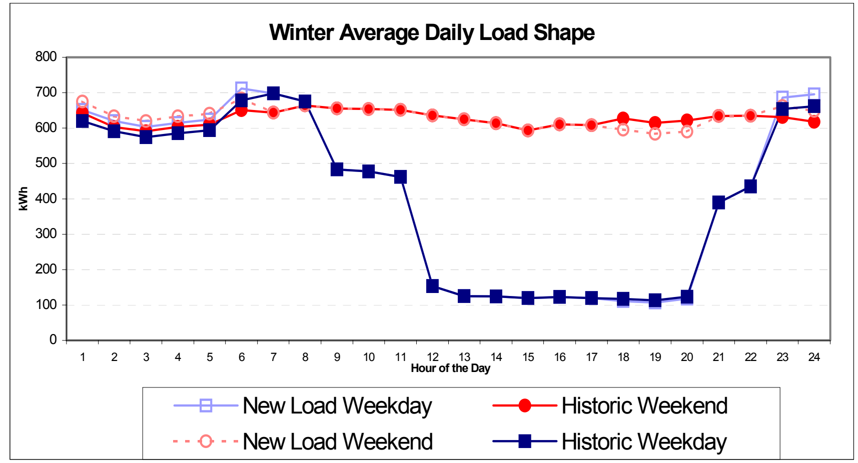
Electric Energy Commodity Cost Comparison (Excludes T&D rate impacts)

New Load assumes 5% decrease in on-peak consumption & 5% increase in off-peak consumption.

			Data				**Benefit of HPO**	**Benefit of HPO & New Load**
Year	Month	Season	Hist. Load w/ EECC Px	Hist. Load w/ HPO Px	New Load w/ EECC Px	New Load w/ HPO Px		
2001	1	Winter	$0	$0	$0	$0	$0	$0
	2	Winter	$0	$0	$0	$0	$0	$0
	3	Winter	$0	$0	$0	$0	$0	$0
	4	Winter	$0	$0	$0	$0	$0	$0
	5	Summer	$0	$0	$0	$0	$0	$0
	6	Summer	$0	$0	$0	$0	$0	$0
	7	Summer	$0	$0	$0	$0	$0	$0
	8	Summer	$0	$0	$0	$0	$0	$0
	9	Summer	$2,383	$2,400	$2,363	$2,375	-$16	$8
	10	Winter	$3,626	$3,668	$3,637	$3,668	-$42	-$42
	11	Winter	$4,289	$4,324	$4,306	$4,325	-$35	-$36
	12	Winter	$5,249	$5,278	$5,277	$5,285	-$29	-$36
2002	1	Winter	$5,214	$5,217	$5,242	$5,228	-$3	-$15
	2	Winter	$1,715	$1,709	$1,727	$1,717	$7	-$2
	3	Winter	$0	$0	$0	$0	$0	$0
	4	Winter	$0	$0	$0	$0	$0	$0
	5	Summer	$0	$0	$0	$0	$0	$0
	6	Summer	$0	$0	$0	$0	$0	$0
	7	Summer	$0	$0	$0	$0	$0	$0
	8	Summer	$0	$0	$0	$0	$0	$0
	9	Summer	$0	$0	$0	$0	$0	$0
Grand Total			$22,476	$22,595	$22,552	$22,599	-$118	-$123

Customer: Refrigerated Warehouse



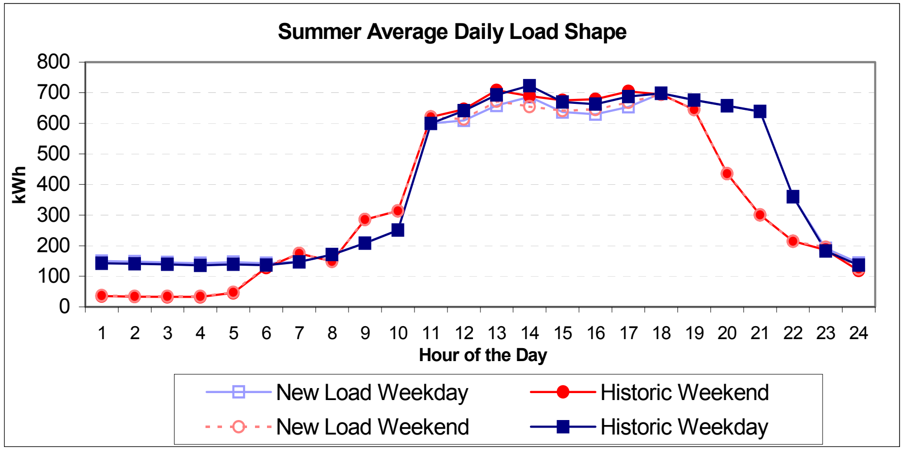


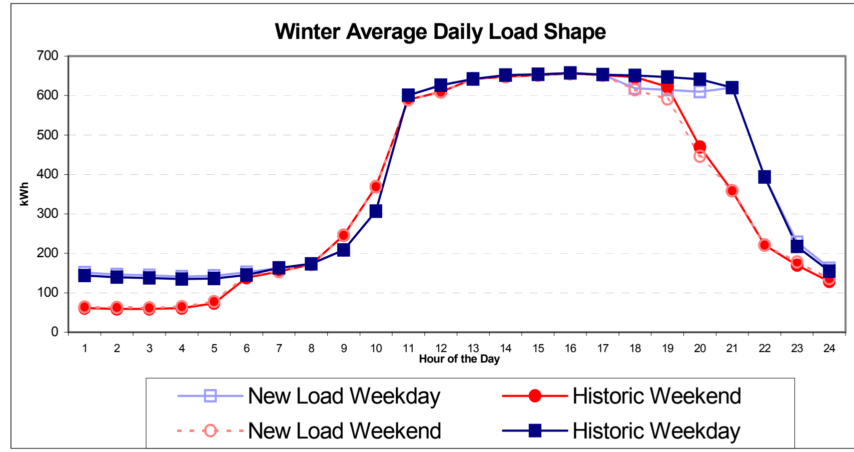
Electric Energy Commodity Cost Comparison (Excludes T&D rate impacts)

New Load assumes 5% decrease in on-peak consumption & 5% increase in off-peak consumption.

			Data				**Benefit of HPO**	**Benefit of HPO & New Load**
Year	Month	Season	Hist. Load w/ EECC Px	Hist. Load w/ HPO Px	New Load w/ EECC Px	New Load w/ HPO Px		
2001	1	Winter	$0	$0	$0	$0	$0	$0
	2	Winter	$0	$0	$0	$0	$0	$0
	3	Winter	$0	$0	$0	$0	$0	$0
	4	Winter	$0	$0	$0	$0	$0	$0
	5	Summer	$0	$0	$0	$0	$0	$0
	6	Summer	$0	$0	$0	$0	$0	$0
	7	Summer	$11,322	$10,397	$11,486	$10,478	$924	$844
	8	Summer	$35,538	$32,545	$36,064	$32,827	$2,993	$2,711
	9	Summer	$30,940	$30,038	$31,336	$30,327	$902	$613
	10	Winter	$27,140	$25,331	$27,648	$25,701	$1,809	$1,440
	11	Winter	$26,551	$24,920	$27,031	$25,279	$1,631	$1,272
	12	Winter	$11,926	$11,139	$12,140	$11,297	$786	$628
2002	1	Winter	$0	$0	$0	$0	$0	$0
	2	Winter	$0	$0	$0	$0	$0	$0
	3	Winter	$0	$0	$0	$0	$0	$0
	4	Winter	$0	$0	$0	$0	$0	$0
	5	Summer	$0	$0	$0	$0	$0	$0
	6	Summer	$0	$0	$0	$0	$0	$0
	7	Summer	$0	$0	$0	$0	$0	$0
	8	Summer	$0	$0	$0	$0	$0	$0
	9	Summer	$0	$0	$0	$0	$0	$0
Grand Total			$143,417	$134,371	$145,706	$135,909	$9,046	$7,508

Customer: Department Store



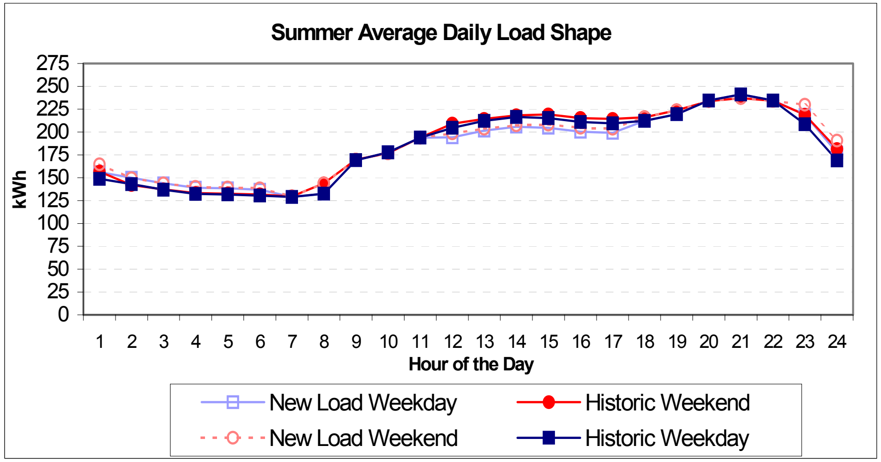


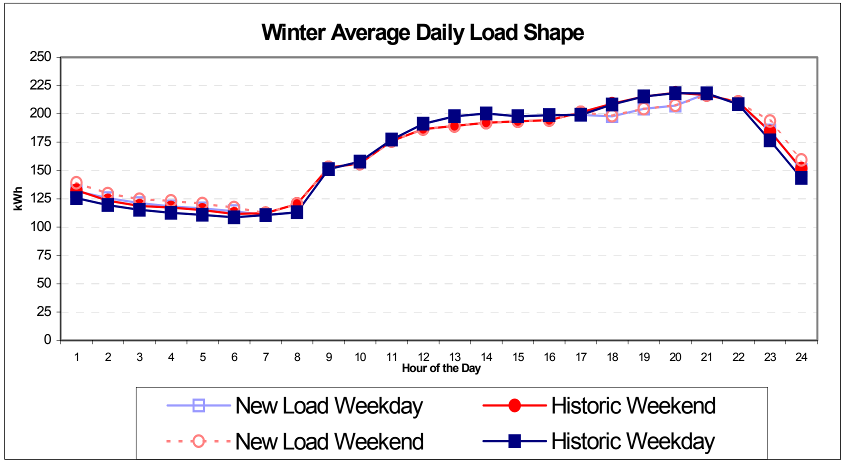
Electric Energy Commodity Cost Comparison (Excludes T&D rate impacts)

New Load assumes 5% decrease in on-peak consumption & 5% increase in off-peak consumption.

			Data					
Year	Month	Season	Hist. Load w/ EECC Px	Hist. Load w/ HPO Px	New Load w/ EECC Px	New Load w/ HPO Px	**Benefit of HPO**	**Benefit of HPO & New Load**
2001	1	Winter	$26,002	$28,675	$25,858	$28,294	-$2,672	-$2,292
	2	Winter	$20,618	$23,014	$20,458	$22,700	-$2,396	-$2,082
	3	Winter	$23,628	$26,007	$23,475	$25,674	-$2,379	-$2,045
	4	Winter	$22,067	$23,955	$21,940	$23,719	-$1,888	-$1,652
	5	Summer	$20,084	$21,706	$19,700	$21,195	-$1,622	-$1,111
	6	Summer	$0	$0	$0	$0	$0	$0
	7	Summer	$0	$0	$0	$0	$0	$0
	8	Summer	$0	$0	$0	$0	$0	$0
	9	Summer	$0	$0	$0	$0	$0	$0
	10	Winter	$0	$0	$0	$0	$0	$0
	11	Winter	$0	$0	$0	$0	$0	$0
	12	Winter	$0	$0	$0	$0	$0	$0
2002	1	Winter	$0	$0	$0	$0	$0	$0
	2	Winter	$0	$0	$0	$0	$0	$0
	3	Winter	$0	$0	$0	$0	$0	$0
	4	Winter	$0	$0	$0	$0	$0	$0
	5	Summer	$0	$0	$0	$0	$0	$0
	6	Summer	$0	$0	$0	$0	$0	$0
	7	Summer	$0	$0	$0	$0	$0	$0
	8	Summer	$0	$0	$0	$0	$0	$0
	9	Summer	$0	$0	$0	$0	$0	$0
Grand Total			$112,399	$123,356	$111,432	$121,581	-$10,957	-$9,182

Customer: Large Restaurant



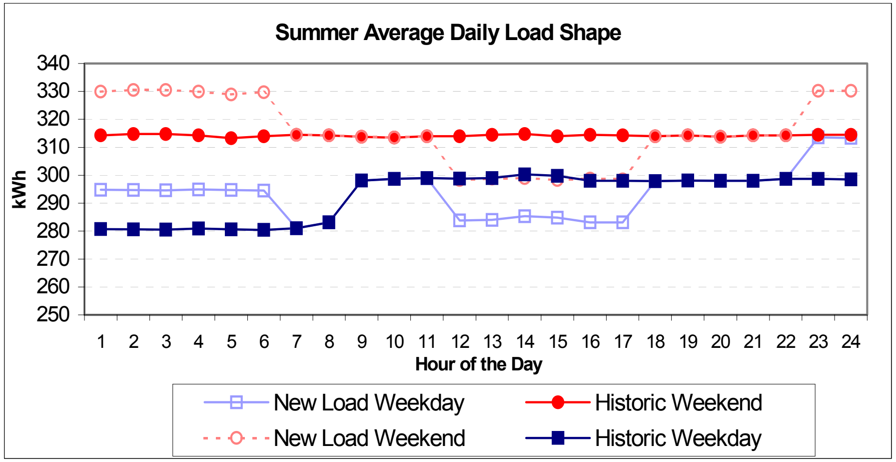


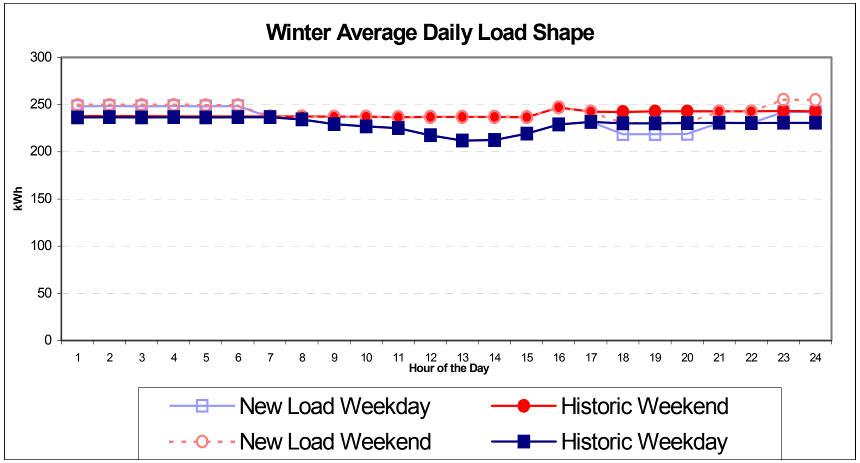
Electric Energy Commodity Cost Comparison (Excludes T&D rate impacts)

New Load assumes 5% decrease in on-peak consumption & 5% increase in off-peak consumption.

			Data					
Year	Month	Season	Hist. Load w/ EECC Px	Hist. Load w/ HPO Px	New Load w/ EECC Px	New Load w/ HPO Px	**Benefit of HPO**	**Benefit of HPO & New Load**
2001	1	Winter	$0	$0	$0	$0	$0	$0
	2	Winter	$0	$0	$0	$0	$0	$0
	3	Winter	$0	$0	$0	$0	$0	$0
	4	Winter	$0	$0	$0	$0	$0	$0
	5	Summer	$0	$0	$0	$0	$0	$0
	6	Summer	$0	$0	$0	$0	$0	$0
	7	Summer	$0	$0	$0	$0	$0	$0
	8	Summer	$10,200	$10,102	$10,168	$10,018	$98	$182
	9	Summer	$10,670	$10,661	$10,631	$10,601	$9	$69
	10	Winter	$10,472	$10,439	$10,510	$10,441	$33	$32
	11	Winter	$10,040	$10,091	$10,070	$10,083	-$51	-$42
	12	Winter	$8,177	$8,277	$8,194	$8,263	-$100	-$87
2002	1	Winter	$0	$0	$0	$0	$0	$0
	2	Winter	$0	$0	$0	$0	$0	$0
	3	Winter	$0	$0	$0	$0	$0	$0
	4	Winter	$0	$0	$0	$0	$0	$0
	5	Summer	$0	$0	$0	$0	$0	$0
	6	Summer	$0	$0	$0	$0	$0	$0
	7	Summer	$0	$0	$0	$0	$0	$0
	8	Summer	$0	$0	$0	$0	$0	$0
	9	Summer	$0	$0	$0	$0	$0	$0
Grand Total			$49,559	$49,570	$49,573	$49,406	-$11	$153

Customer: Water District





Electric Energy Commodity Cost Comparison (Excludes T&D rate impacts)

New Load assumes 5% decrease in on-peak consumption & 5% increase in off-peak consumption.

			Data					
Year	Month	Season	Hist. Load w/ EECC Px	Hist. Load w/ HPO Px	New Load w/ EECC Px	New Load w/ HPO Px	**Benefit of HPO**	**Benefit of HPO & New Load**
2001	1	Winter	$0	$0	$0	$0	$0	$0
	2	Winter	$0	$0	$0	$0	$0	$0
	3	Winter	$0	$0	$0	$0	$0	$0
	4	Winter	$0	$0	$0	$0	$0	$0
	5	Summer	$0	$0	$0	$0	$0	$0
	6	Summer	$0	$0	$0	$0	$0	$0
	7	Summer	$0	$0	$0	$0	$0	$0
	8	Summer	$0	$0	$0	$0	$0	$0
	9	Summer	$0	$0	$0	$0	$0	$0
	10	Winter	$0	$0	$0	$0	$0	$0
	11	Winter	$0	$0	$0	$0	$0	$0
	12	Winter	$0	$0	$0	$0	$0	$0
2002	1	Winter	$18,010	$17,757	$18,169	$17,855	$253	$156
	2	Winter	$28,108	$27,672	$28,364	$27,843	$436	$265
	3	Winter	$7,922	$7,759	$7,999	$7,806	$163	$116
	4	Winter	$85	$83	$86	$83	$3	$2
	5	Summer	$15,879	$15,732	$15,895	$15,722	$147	$156
	6	Summer	$0	$0	$0	$0	$0	$0
	7	Summer	$0	$0	$0	$0	$0	$0
	8	Summer	$0	$0	$0	$0	$0	$0
	9	Summer	$0	$0	$0	$0	$0	$0
Grand Total			$70,004	$69,003	$70,513	$69,309	$1,002	$695